AMERICAN ELECTRIC POWER CO INC
Form 10-Q
April 26, 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 March 31, 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 and posted on their corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes x No ¨

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

Smaller reporting company ¨
Emerging growth company ¨

Indicate by check mark whether AEP 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 (Do not check if a smaller reporting company)

Smaller reporting company ¨
Emerging growth company ¨

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

Indicate by check mark

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

AEP 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 April 26, 2018
American Electric Power Company, Inc.	492,523,470 ($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
March 31, 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 Accumulated Deferred Income Taxes for ratemaking purposes.
ASC	Accounting Standard Codification.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CAIR	Clean Air Interstate Rule.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VI LLC, DCC Fuel VII, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X and DCC Fuel XI consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	

	Desert Sky Wind Farm, a 160.5 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.

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Term	Meaning
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.
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.
Market Based Mechanism	An order from the LPSC established to evaluate proposals to construct or acquire generating capacity. The LPSC directs that the market based mechanism shall be a request for proposal competitive solicitation process.
MISO	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.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
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.
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 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.

TNC	Formerly Texas North Company, now a division of AEP Texas.
TRA	Tennessee Regulatory Authority.
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.

Term	Meaning
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 150 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
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 which includes the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

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 accumulated deferred income taxes.

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 first quarter of 2018 increased by 1.5% from the first quarter of 2017. AEP's first quarter 2018 industrial sales volumes increased 2.5% compared to the first quarter of 2017. The growth in industrial sales was spread across most industries and most operating companies. Weather-normalized residential and commercial sales increased 1.4% and 0.5% in the first quarter of 2018, respectively, from the first quarter of 2017.

Federal Tax Reform

In December 2017, legislation referred to as Tax Reform was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, (the Code) 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, eliminate bonus depreciation for certain property acquired after September 27, 2017 and continue certain rate normalization requirements for accelerated depreciation benefits.

The Registrants expect the mechanism and time period to provide the benefits of Tax Reform to customers will continue to vary by jurisdiction. Tax Reform did not have a material impact on net income in the first quarter of 2018 and is not expected to have a material impact on future net income. However, the Registrants anticipate 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 accumulated deferred income taxes (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 second half 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. During the first quarter of 2018, AEP recorded estimated provisions for revenue refunds totaling $120 million as a result of the reduction in the corporate federal tax rate.

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Excess Accumulated Deferred Income Taxes - Pending Rate Reductions

As of March 31, 2018, the Registrants have approximately $4.4 billion of Excess ADIT, as well as an incremental liability of $1.2 billion to reflect the $4.4 billion Excess ADIT on a pre-tax 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 March 31, 2018, approximately $3.4 billion of the Excess ADIT relates to temporary differences associated with 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. This amortization resulted in a $17 million reduction in Income Tax Expense in the first quarter of 2018. As a result of state utility commission orders or instructions, the Registrants recorded estimated provisions for revenue refund offsetting the amortization of the Excess ADIT totaling $17 million in the first quarter of 2018.

In addition, with respect to the remaining $1 billion of Excess ADIT recorded in Regulatory Liabilities and Deferred Investment Tax Credits that are not subject to rate normalization requirements, the Registrants continue to work with the various state utility commissions to determine the appropriate mechanism and time period to provide these benefits of Tax Reform to customers. The corresponding reduction in Income Tax Expense will be reported in the interim period in which these benefits of Tax Reform are provided to customers.

Merchant Generation Assets

In September 2016, AEP signed an agreement to sell Darby, Gavin, Lawrenceburg and Waterford Plants totaling 5,329 MWs of competitive generation to a nonaffiliated party. The sale closed in January 2017 for approximately $2.2 billion. The net proceeds from the transaction were approximately $1.2 billion in cash after taxes, repayment of debt associated with these assets and transaction fees, which resulted in an after tax gain of approximately $129 million. AEP primarily used these proceeds to reduce outstanding debt and invest in its regulated businesses including transmission, and contracted renewable projects. See "Dispositions" section of Note 6 for additional information.

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

In December 2017, AEP signed an amendment to the Cardinal Station Agreement with Buckeye Power Incorporated, which terminates certain commercial arrangements between the parties and transitions management oversight and administrative support of the Cardinal facility from AEP to Buckeye Power Incorporated. The amendment required approval from Rural Utilities Service and the FERC, which were obtained in February 2018. The new amendment became effective March 2018 and did not have a material impact on net income, cash flows or financial condition.

Management continues to evaluate potential alternatives for its remaining merchant generation assets. These potential alternatives may include, but are not limited to, transfer or sale of AEP's ownership interests or a wind down of merchant coal-fired generation fleet operations. Management has not set a specific time frame for a decision on these assets. These alternatives could result in additional losses which could reduce future net income and cash flows and impact financial condition.

Renewable Generation Portfolio

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

Contracted Renewable Generation Facilities

AEP 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 March 31, 2018, subsidiaries within AEP's Generation & Marketing segment have approximately 400 MWs of contracted renewable generation projects in operation. In addition, as of March 31, 2018, these subsidiaries have approximately 10 MWs of new renewable generation projects under construction with total estimated capital costs of $26 million related to these projects.

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, which is expected to be completed in 2018. The nonaffiliated member contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. AEP's 79.9% share of the LLCs, or 248 MWs, represents $232 million of additional estimated capital, of which $131 million has been incurred and recorded in CWIP as of March 31, 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. The wind generating facilities are located in West Virginia and Ohio and, if approved, are anticipated to be in-service in the second half of 2019. APCo will assume ownership of the facilities at or near the anticipated in-service date. APCo currently plans to sell the Renewable Energy Certificates associated with the generation from these facilities. In December 2017, the WVPSC staff and an industrial intervenor filed testimony in West Virginia and the Virginia SCC staff filed testimony in Virginia arguing that APCo's forecast of natural gas and energy prices was too high and, with the exception of the WVPSC staff's recommended approval of the facility located in West Virginia, did not support approval of APCo's acquisition of the facilities. In January 2018, APCo filed supplemental testimony with the WVPSC to address changes in the economics of the wind projects as a result of Tax Reform. A hearing at the WVPSC was held in March 2018 and briefs were filed in April 2018. The WVPSC staff, the industrial intervenor and the Consumer Advocate Division of the Public Service Commission all recommended that the WVPSC deny APCO's request for approval of the wind farms. Also 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 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 includes 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 380 miles. Total investment for the project is estimated to be $4.5 billion and will serve both retail and FERC wholesale load. PSO and SWEPCo will have a 30% and 70% ownership share, respectively, in these assets. The wind generating facility is located in Oklahoma and, if approved by all state commissions, is anticipated to be in-service by the end of 2020. In July 2017, the LPSC approved SWEPCo's request for an exemption to the Market Based Mechanism. In August 2017 and December 2017, the OCC denied the Oklahoma Attorney General's respective August and December 2017 motions to dismiss. Also in December 2017, the companies filed a request at the FERC to transfer the wind generation facility to PSO and SWEPCo upon its construction by a third party, which was approved in April 2018. The transfer remains subject to the approval of the project at the respective state commissions. Parties' testimony filed in the Oklahoma, Texas and

Louisiana dockets generally opposes the companies' request. In February 2018, the ALJ in Oklahoma recommended that PSO's request for preapproval of future recovery of Wind Catcher Project costs be denied. In March 2018, oral arguments were held before three Oklahoma Commissioners regarding the ALJ report and parties agreed to waive the 240 day statutory deadline for an order to continue the discussions. A non-unanimous settlement agreement was filed in Arkansas in

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February 2018, a unanimous settlement was filed in April 2018 in Louisiana and a non-unanimous settlement was filed in April 2018 in Oklahoma, with further settlement discussion continuing. The settlement agreements and the companies' rebuttal testimony filed in Oklahoma, Texas, Arkansas and Louisiana, generally contain certain commitments of PSO and SWEPCo, including a most favored nation clause, a cap on the cost of the investment, guarantees of qualification for production tax credits, minimum annual production from the project and a net benefits guarantee for ten years. In addition, PSO and SWEPCo committed in each jurisdiction to the timely filing of a base rate case to shorten the duration of cost recovery through a temporary mechanism.

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. As rebuilding efforts continue, AEP Texas' total costs related to this storm are not yet final. AEP Texas' current estimated cost is approximately $325 million to $375 million, including capital expenditures. 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 annually through base rates. As of March 31, 2018, the total balance of AEP Texas' catastrophe reserve deferral is $129 million, inclusive of approximately $105 million of net incremental storm expenses related to Hurricane Harvey. As of March 31, 2018, AEP Texas has recorded approximately $186 million of capital expenditures related to Hurricane Harvey. Also, as of March 31, 2018, AEP Texas has received $10 million in insurance proceeds, which were applied to the regulatory asset and property, plant and equipment. 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 also 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 AEP Texas is currently evaluating recovery options for the regulatory asset, including securitization. The standard process for storm cost recovery in Texas requires two filings with the PUCT. Management expects the first filing by the end of third quarter of 2018. If the ultimate costs of the incident are not recovered by insurance or through the regulatory process, it would have an adverse effect on future net income, cash flows and financial condition.

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

In March 2016, a contested stipulation agreement related to the PPA rider application was modified and approved by the PUCO. The approved PPA rider is subject to audit and review by the PUCO. Consistent with the terms of the modified and approved stipulation agreement, and based upon a September 2016 PUCO order, in November 2016, OPCo refiled its amended ESP extension application and supporting testimony. The amended filing proposed to extend the ESP through May 2024 and included (a) an extension of the OVEC PPA rider, (b) a proposed 10.41% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's DIR and (e) the addition of various new riders, including a Renewable Resource Rider.

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

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

In April 2018, the PUCO issued an order approving the stipulation agreement, with no significant changes.

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 second half of 2018. 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 by December 2019. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. As of March 31, 2018, total costs incurred related to this project, including AFUDC, were approximately $28 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

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 accounting for 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 I&M's

existing Indiana Clean Coal Technology Rider.

In April 2018, a group of intervenors filed a Petition for Reconsideration and Rehearing of the March 2018 IURC order. The intervenors requested that the IURC reopen the proceeding primarily to address whether allowing I&M any cost recovery for the SCR would constitute a cross-subsidization issue and to reverse its finding approving cost recovery for the Rockport Plant, Unit 2 SCR project. Also in April 2018, I&M filed a response to the intervenors' petition.

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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 November 2017, various intervenors filed testimony that included annual revenue increase recommendations ranging from $125 million to $152 million. The recommended returns on common equity ranged from 8.65% to 9.1%. In addition, certain parties recommended longer recovery periods than I&M proposed for recovery of regulatory assets and depreciation expenses related to Rockport Plant, Units 1 and 2. In January 2018, in response to a January 2018 IURC request related to the impact of Tax Reform on I&M's pending base rate case, I&M filed updated schedules supporting a $191 million annual increase in Indiana base rates if the effect of Tax Reform was included in the cost of service.

In February 2018, I&M and all parties to the case, except one industrial customer, 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 one industrial customer agreed to not oppose the Stipulation and Settlement Agreement. The difference between I&M's requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement is primarily a result of: (a) the reduction in the federal income tax rate due to Tax Reform, (b) the feedback of credits for excess deferred income taxes, (c) a 9.95% return on equity, (d) longer recovery periods of regulatory assets, (e) lower depreciation expense primarily for meters and (f) an increase in the sharing of off-system sales margins with customers from 50% to 95%. If the Stipulation and Settlement is approved, I&M will also refund $4 million from July through December 2018 for the impact of Tax Reform for the period January through June 2018. A hearing at the IURC was held in March 2018 and an IURC order is expected in the second quarter of 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project.

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenors' proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day and 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 until adjusted in the next base rate case.

In April 2018, the MPSC issued an order that generally approved the ALJ proposal resulting in an annual revenue increase of $49 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.

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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 March 31, 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.

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. The net annual increase is subject to refund. In October 2017, SWEPCo filed testimony in Louisiana supporting the prudence of its environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants. These environmental costs are subject to prudence review. A hearing at the LPSC is scheduled for May 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 will be effective August 2018. The filing included a reduction in the federal income tax rate due to Tax Reform. The return of excess deferred income tax benefits to customers will be addressed in a supplemental filing and will reduce the $28 million annual increase. The increase includes SWEPCo's jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls, whose prudence review hearing is scheduled for May 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 February 2018, the KPSC issued an order granting rehearing of these items, with an exception for the capital structure adjustments, which was denied by the KPSC.

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 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 includes $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 expenses. 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. This order is subject to appeal as early as the second quarter of 2018. 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 deferred income tax benefits to customers.

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 will: (a) on a one-time basis, require APCo to exclude $10 million of fuel expenses from the July 2018 over/under calculation, (b) reduce APCo’s base rates by $50 million annually no later than July 30, 2018, on an interim basis and subject to true-up, to reflect the lower federal income tax rate due to Tax Reform, (c) 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) 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) require APCo to obtain 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 from July 1, 2018 through July 1, 2028 and (f) require APCo to construct and/or acquire solar generation facilities in Virginia of at least 200 MW of aggregate capacity. Triennial reviews are subject to an earnings test which provides that any over earnings may be reinvested in approved energy distribution grid transformation projects. The Virginia SCC’s triennial review of 2017-2019 APCo earnings 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, to be 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 accumulated deferred income taxes that are 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, pending the FERC's consideration of the settlement, and the 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. In addition, the FERC trial staff filed comments recommending a base ROE of 8.41% and one-time refund of $175 million. Also in April 2018, another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. Management intends to file reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement.

Management believes the $50 million refund in the settlement agreement is the best estimate of the probable liability. 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. In November 2017, a FERC order set the matter for hearing and settlement procedures. Management believes its financial statements adequately address the impact of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's 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 2018 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.

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

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

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could total approximately $850 million, excluding AFUDC. As of March 31, 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 March 31, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $625 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 $11 million, excluding $6 million of unrecognized equity as of March 31, 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. In January 2018, SWEPCo received written approval from the PUCT to recover its project costs from retail customers in its 2016 Texas base rate case and is recovering these costs from wholesale customers through SWEPCo's FERC-approved agreements. See "2016 Texas Base Rate Case" and "2017 Louisiana Formula Rate Filing" disclosures above.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. 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, a nonaffiliated third party. Pursuant to the sale, Brookfield will assume all of I&M's contracts with Westinghouse. The sale is subject to regulatory approvals and is expected to close in the third quarter of 2018.

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 will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiffs further allege that the defendants' actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M.

In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims, including the dismissal without prejudice of plaintiffs' claims seeking compensatory damages. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiffs' motion for partial judgment and filed a motion to dismiss the case for failure to state a claim.

In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, plaintiffs filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether AEGCo and I&M are in breach of certain contract provisions that plaintiffs allege operate to protect the plaintiffs' residual interests in the unit and whether the trial court erred in dismissing plaintiffs' claims that AEGCo and I&M breached the covenant of good faith and fair dealing.

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

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio 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. 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.

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 March 31, 2018, the AEP System had a total generating capacity of approximately 25,600 MWs, of which approximately 13,500 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP's investment to meet these existing and proposed requirements ranges from approximately $2.1 billion to $2.7 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 and (g) other factors. In addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and competitive plants.

The table below represents the plants or units of plants retired in 2016 and 2015 with a remaining net book value. As of March 31, 2018, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the units listed below was approved for recovery, except for $218 million. Management is seeking or will seek recovery of the remaining net book value of $218 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
I&M (b)	Tanners Creek Plant	995	27.7
SWEPCo	Welsh Plant, Unit 2	528	50.6
Total		3,263	$ 218.1

(a) APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert its 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively.

(b) I&M requested recovery of the Indiana (approximately 65%) and Michigan (approximately 14%) jurisdictional shares of the remaining retirement costs of Tanners Creek Plant in the 2017 Indiana and Michigan base rate cases. In April 2018, a final order was received in Michigan which approved I&M's request for a return of and on its jurisdictional share of the remaining retirement costs of Tanners Creek Plant. See "2017 Indiana Base Rate Case" and "2017 Michigan Base Rate Case" sections of Note 4 for additional information.

In January 2017, Dayton Power and Light Company announced the future retirement of the 2,308 MW Stuart Plant, Units 1-4. The retirement is scheduled for June 2018. Stuart Plant, Units 1-4 are operated by Dayton Power and Light Company and are jointly owned by AGR and nonaffiliated entities. AGR owns 600 MWs of the Stuart Plant, Units 1-4. As of March 31, 2018, AGR's net book value of the Stuart Plant, Units 1-4 was zero.

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 the AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when 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 district court granted AEP's request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until June 2020. AEP also proposed to retire Conesville Plant, Units 5 and 6 by December 31, 2022 and to retire one unit at Rockport Plant by December 31, 2028. Plaintiffs opposed AEP's motion.

In January 2018, AEP filed a supplemental motion proposing to install the SCR at Rockport Plant, Unit 2 and achieve the final SO2 emission cap applicable to the plant under the consent decree by the end of 2020, before the expiration of the initial lease term. Responsive filings were filed in February 2018 by parties opposing AEP's proposed modifications to the consent decree. AEP was directed to file a detailed statement of the specific relief requested to address the changed circumstances at Rockport, and the opposing parties were provided with an opportunity to respond thereto. The motion remains pending and a decision from the court is expected in 2018.

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. States are still in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the 2010 SO_2 NAAQS. In December 2017, the Federal EPA published final designations for certain areas’ compliance with the 2010 SO_2 NAAQS. States may develop additional requirements for AEP’s facilities as a result of these designations. In April 2017, the Federal EPA requested a stay of proceedings in the U.S. Court of Appeals for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. The Federal EPA initially announced a one-year delay in the designation of ozone non-attainment areas, but withdrew that decision. In December 2017, the Federal EPA issued a notice of data availability and requested public comment on recommended designations for compliance with the 2015 ozone standard. In March 2018, the Federal EPA responded to additional data regarding certain areas submitted by Texas. The Federal EPA anticipates completing the designations process within 120 days of providing notice to the states. 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. State implementation plans for the 2015 ozone standard are due in October 2018. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP’s facilities based on the outcome of these activities.

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Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) will address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. In January 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

The Federal EPA proposed disapproval of regional haze SIPs in a few states, including Arkansas and Texas. In March 2012, the Federal EPA disapproved certain portions of the Arkansas regional haze SIP. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that were consistent with the environmental controls under construction. In September 2016, the Federal EPA published a final FIP that retains its BART determinations, but accelerates the schedule for implementation of certain required controls. The final rule is being challenged in the courts. In March 2017, the Federal EPA filed a motion that was granted by the U.S. Court of Appeals for the Eighth Circuit to hold the case in abeyance for 90 days to allow the parties to engage in settlement negotiations. Arkansas issued a proposed SIP revision to allow sources to participate in the CSAPR ozone season program in lieu of the source-specific NO_x BART requirements in the FIP, and the Federal EPA has approved that SIP revision. Arkansas issued a second proposal to revise the SO_2 BART determinations, and the public comment period on that action has closed. The Federal EPA has asked the Eighth Circuit to continue to hold litigation in abeyance to facilitate settlement discussions. Arkansas and other affected parties filed motions to stay the compliance deadlines pending further action from the Federal EPA and the motion was granted. Management cannot predict the outcome of these proceedings.

In January 2016, the Federal EPA disapproved portions of the Texas regional haze SIP and promulgated a final FIP that did not include any BART determinations. That rule was challenged and stayed by the U.S. Court of Appeals for the Fifth Circuit. The parties engaged in a settlement discussion but were unable to reach an agreement. In March 2017, the U.S. Court of Appeals for the Fifth Circuit granted partial remand of the final rule. In January 2017, the Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including Welsh Plant, Unit 1. Management submitted comments on the proposal and engaged in discussions with the Texas Commission on Environmental Quality (TCEQ) regarding the development of an alternative to source-specific BART. In September 2017, the Federal EPA issued a final rule withdrawing Texas from the annual CSAPR budget programs and reaffirming CSAPR as a BART alternative. The Federal EPA then issued a separate rule finalizing the regional haze requirements for electric generating units in Texas and confirmed TCEQ's determination that no new PM limitations are required for regional haze. The Federal EPA also finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations as an alternative to source-specific SO_2 requirements. The proposed source-specific approach called for a wet FGD system to be installed on Welsh Plant, Unit 1. The opportunity to use emissions trading to satisfy the regional haze requirements for NO_x and SO_2 at AEP's affected generating units provides greater flexibility and lower cost compliance options than the original proposal. 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. 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. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the Federal EPA rule.

CSAPR

In 2011, the Federal EPA issued CSAPR as a replacement for the CAIR, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind nonattainment with the 1997 ozone and PM NAAQS. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. The court stayed implementation of the rule. Following extended proceedings in the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court, but while the litigation was still pending, the U.S. Court of Appeals for the District of Columbia Circuit granted the Federal EPA's motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In October 2016, a final rule was issued to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduces ozone season budgets in many states and discounts the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. 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. In a related case, other parties challenged in the U.S. Court of Appeals for the District of Columbia Circuit a final rule withdrawing Texas from the CSAPR annual program and reaffirming that compliance with CSAPR remained better than compliance with BART. The U.S. Court of Appeals for the District of Columbia Circuit granted a motion in March 2018 to hold the case in abeyance until completion of the Federal EPA's review of pending petitions for reconsideration of the Texas regional haze rule discussed above.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance was required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the April 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court and the court granted those petitions in November 2014.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule for further proceedings consistent with the U.S. Supreme Court's decision that the Federal EPA was unreasonable in refusing to consider costs in its determination whether to regulate emissions of HAPs from power plants. The Federal EPA issued notice of a supplemental finding concluding that it is appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Management submitted comments on the proposal. In April 2016, the Federal EPA affirmed its determination that regulation of HAPs from electric generating units is necessary and appropriate. Petitions for review of the Federal EPA's April 2016 determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was scheduled for May 2017, but in April 2017 the Federal EPA requested that oral argument be postponed to facilitate its review of the rule. The rule remains in effect.

Climate Change, CO_2 Regulation and Energy Policy

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

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

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

The Federal EPA also published proposed "model" rules that could be adopted by the states that would allow sources within "trading ready" state programs to trade, bank or sell allowances or credits issued by the states. These rules would also be the basis for any federal plan issued by the Federal EPA in a state that fails to submit or receive approval for a state plan. In June 2016, the Federal EPA issued a separate proposal for the Clean Energy Incentive Program (CEIP) that was included in the model rules.

The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In April 2017, the Federal EPA withdrew its previously issued proposals for model trading rules and a CEIP.

In March 2017, the Federal EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of: (a) an Executive Order from the President of the United States titled "Promoting Energy Independence and Economic Growth" directing the Federal EPA to review the CPP and related rules; (b) the Federal EPA's initiation of a review of the CPP and (c) a forthcoming rulemaking related to the CPP consistent with the Executive Order, if the Federal EPA determines appropriate. In this same filing, the Federal EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review of any resulting rulemaking. The District of Columbia Circuit granted the Federal EPA's motion in part and has requested periodic status reports. In October 2017, the Federal EPA issued a proposed rule repealing the CPP and withdrawing the legal memoranda issued in connection with the rule. The Federal EPA has re-examined its legal interpretation of the "best system of emission reduction" and found that based on the statutory text, legislative history, use of similar terms elsewhere in the CAA and its own historic implementation of Section 111 that a narrower interpretation of the term limits it to those designs, processes, control technologies and other systems that can be applied directly to or at the source. Since the primary systems relied on in the CPP are not consistent with that interpretation, the Federal EPA proposes that the rule be withdrawn. The comment period on the proposed repeal has been extended to April 2018. 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 guidelines for state programs. 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. 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, regulations, and grid reliability and resiliency, and reflect 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 and could lead to possible impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The final rule has been challenged in the courts.

The final rule became effective in October 2015. CCR are regulated as non-hazardous solid wastes and facilities managing CCR must meet new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes 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.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the Federal EPA to approve such programs if they are no less stringent than the minimum federal standards. The Federal EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs. In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule and asked that litigation regarding the rule be held in abeyance. The U.S. Court of Appeals for the District of Columbia Circuit heard oral argument in November 2017. 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. The comment period is open until the end of April 2018. 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. Comments are due in May 2018. Management is unable to predict the outcome of these cases on the Federal EPA's rulemaking, but they 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 at some point in the future as the new rule is implemented. Management recorded a $95 million increase in asset retirement obligations in 2015 primarily due to the publication of the final rule. Management will continue to evaluate the rule's impact on operations.

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Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's NPDES permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The final rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations filed a petition for reconsideration of the rule with the Federal EPA. In April 2017, the Federal EPA granted reconsideration of the rule and issued a stay of the rule's future compliance deadlines, which has now expired. In April 2017, the U.S. Court of Appeals for the Fifth Circuit granted a stay of the litigation for 120 days. In June 2017, the Federal EPA also issued a proposal to temporarily postpone certain compliance deadlines in the rule. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017. Management submitted comments supporting the proposed postponement. Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting. 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 CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This jurisdictional definition applies to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a "significant nexus." Management believes that clarity and efficiency in the permitting process is needed. Management remains concerned that the rule introduces new concepts and could subject more of AEP's operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. The U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule pending jurisdictional determinations. In February 2016, the U.S. Court of Appeals for the Sixth Circuit issued a decision holding that it has exclusive jurisdiction to decide the challenges to the "waters of the United States" rule. Industry, state and related associations filed petitions for a rehearing of the jurisdictional decision. In April 2016, the U.S. Court of Appeals for the Sixth Circuit denied the petitions. In January 2017, the decision was appealed to the U.S. Supreme Court, which granted certiorari to review the jurisdictional issue. Oral argument was heard in October

2017. In January 2018, the U.S. Supreme Court ruled that challenges to the definition of "waters of the United States" must be filed in the federal district court, and remanded the case to the U.S. Court of Appeals for the Sixth Circuit with directions to dismiss the petitions for review for lack of jurisdiction. The stay has been lifted and the Sixth Circuit case has been dismissed. Challenges to the rule will proceed in federal district courts.

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. The Federal EPA and U.S. Army Corps of Engineers also finalized a new rule to extend the applicability date of the 2015 rule by two years before the nationwide stay issued by the U.S. Court of Appeals for the Sixth Circuit was lifted. Challenges to the applicability date rule have been filed by third parties in several federal district courts. 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 is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The following discussion of AEP's results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale 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 March 31,	
	2018	2017
	(in millions)	
Vertically Integrated Utilities	$231.2	$219.5
Transmission and Distribution Utilities	125.4	119.1
AEP Transmission Holdco	104.0	71.8
Generation & Marketing	18.2	186.2
Corporate and Other	(24.4)	(4.4)
Earnings Attributable to AEP Common Shareholders	$454.4	$592.2

AEP CONSOLIDATED

First Quarter of 2018 Compared to First Quarter of 2017

Earnings Attributable to AEP Common Shareholders decreased from $592 million in 2017 to $454 million in 2018 primarily due to:

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

This decrease was partially offset by:

- An increase in transmission investment primarily at AEP Transmission Holdco, which resulted in higher revenues and income.
- An increase in weather-related usage.
- Favorable rate proceedings in AEP's various jurisdictions.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended March 31, 2018	2017
	(in millions)	
Revenues	$2,408.0	$2,290.4
Fuel and Purchased Electricity	857.8	788.4
Gross Margin	1,550.2	1,502.0
Other Operation and Maintenance	740.0	660.1
Depreciation and Amortization	313.3	278.3
Taxes Other Than Income Taxes	109.9	101.1
Operating Income	387.0	462.5
Interest and Investment Income	2.6	3.1
Carrying Costs Income	2.8	4.1
Allowance for Equity Funds Used During Construction	7.4	6.2
Non-Service Cost Components of Net Periodic Benefit Cost	18.1	5.9
Interest Expense	(137.9)	(134.9)
Income Before Income Tax Expense and Equity Earnings	280.0	346.9
Income Tax Expense	47.7	127.7
Equity Earnings of Unconsolidated Subsidiaries	0.5	1.3
Net Income	232.8	220.5
Net Income Attributable to Noncontrolling Interests	1.6	1.0
Earnings Attributable to AEP Common Shareholders	$231.2	$219.5

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2018	2017
	(in millions of KWhs)	
Retail:		
Residential	9,572	8,239
Commercial	5,868	5,689
Industrial	8,497	8,264
Miscellaneous	553	536
Total Retail	24,490	22,728
Wholesale (a)	5,738	6,507
Total KWhs	30,228	29,235

(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 March 31, 2018	2017
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,637	1,181
Normal – Heating (b)	1,602	1,615
Actual – Cooling (c)	6	1
Normal – Cooling (b)	5	5
Western Region		
Actual – Heating (a)	881	530
Normal – Heating (b)	875	892
Actual – Cooling (c)	36	82
Normal – Cooling (b)	27	24

(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.

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

First Quarter of 2017	$219.5
Changes in Gross Margin:	
Retail Margins	49.5
Off-system Sales	1.0
Transmission Revenues	2.7
Other Revenues	(5.0)
Total Change in Gross Margin	48.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(79.9)
Depreciation and Amortization	(35.0)
Taxes Other Than Income Taxes	(8.8)
Interest and Investment Income	(0.5)
Carrying Costs Income	(1.3)
Allowance for Equity Funds Used During Construction	1.2
Non-Service Cost Components of Net Periodic Pension Cost	12.2
Interest Expense	(3.0)
Total Change in Expenses and Other	(115.1)
Income Tax Expense	80.0
Equity Earnings	(0.8)
Net Income Attributable to Noncontrolling Interests	(0.6)
First Quarter of 2018	$231.2

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 $50 million primarily due to the following:
- An $89 million increase in weather-related usage primarily in the eastern region.
- The effect of rate proceedings in AEP’s service territories which included:
- A $25 million increase for I&M from rate proceedings primarily in Indiana.
- A $22 million increase for SWEPCo due to rider and base rate revenue increases in Texas and Louisiana.
- An $11 million increase for APCo primarily due to increases from rate riders in Virginia.
- A $4 million increase for PSO due to new rates implemented in March 2018, inclusive of a $2 million decrease due to the change in the corporate federal tax rate.

For the rate increases described above, $26 million relate to riders/trackers, which have corresponding increases in expense items below.
These increases were partially offset by:

- A $71 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
-

A $16 million decrease due to lower weather-normalized margins, primarily due to SWEPCo and I&M wholesale customer load loss from contracts that expired at the end of 2017.

- A $4 million decrease primarily due to increased fuel and other variable production costs not recovered through fuel clauses or other trackers.
- A $4 million decrease for I&M in FERC generation wholesale municipal and cooperative revenues primarily due to changes to the annual formula rate.

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- Transmission Revenues increased $3 million primarily due to an increase in transmission investments in SPP.
- Other Revenues decreased $5 million primarily due to reduced rates for KPCo Demand Side Management programs beginning in 2018. This decrease is partially offset in Other Operation and Maintenance expense below.

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

- Other Operation and Maintenance expenses increased $80 million primarily due to the following:
- A $45 million increase in recoverable expenses, primarily fuel support and PJM expenses fully recovered in rate recovery riders/trackers in Gross Margins above.
- A $15 million increase in plant maintenance primarily for I&M, KPCo and SWEPCo.
- A $14 million increase due to the Wind Catcher Project for SWEPCo and PSO.
- A $10 million increase in transmission services primarily in SPP.
- A $9 million increase due to an increase in estimated expense for claims related to asbestos exposure.

These increases were partially offset by:

- A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2018.
- A $6 million decrease in distribution expenses primarily due to distribution system improvements in 2017.
- Depreciation and Amortization expenses increased $35 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $9 million primarily due to:
- A $4 million increase in state gross receipts tax due to a prior period refund.
- A $3 million increase in property tax driven by an increase in utility plant.
- 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 and by moving to a Medicare Advantage arrangement for post-65 retirees in the Non-UMWA OPEB plan. Additionally, the decrease was partially due to the implementation of ASU 2017-07 in 2018, which eliminated AEP’s ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $80 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 accumulated deferred income taxes associated with certain depreciable property and a decrease in pretax book income.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended March 31, 2018	2017
	(in millions)	
Revenues	$1,162.4	$1,086.4
Purchased Electricity	244.6	223.4
Amortization of Generation Deferrals	58.6	60.9
Gross Margin	859.2	802.1
Other Operation and Maintenance	352.7	287.9
Depreciation and Amortization	172.6	156.2
Taxes Other Than Income Taxes	137.4	126.9
Operating Income	196.5	231.1
Interest and Investment Income	1.4	3.5
Carrying Costs Income	0.7	1.9
Allowance for Equity Funds Used During Construction	8.0	4.2
Non-Service Cost Components of Net Periodic Benefit Cost	8.2	2.2
Interest Expense	(60.1)	(60.0)
Income Before Income Tax Expense	154.7	182.9
Income Tax Expense	29.3	63.8
Net Income	125.4	119.1
Net Income Attributable to Noncontrolling Interests	—	—
Earnings Attributable to AEP Common Shareholders	$125.4	$119.1

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2018	2017
	(in millions of KWhs)	
Retail:		
Residential	6,797	5,894
Commercial	5,864	5,753
Industrial	5,514	5,476
Miscellaneous	153	160
Total Retail (a)	18,328	17,283
Wholesale (b)	667	798
Total KWhs	18,995	18,081

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

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,884	1,403
Normal – Heating (b)	1,884	1,899
Actual – Cooling (c)	4	3
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	230	102
Normal – Heating (b)	191	195
Actual – Cooling (d)	196	258
Normal – Cooling (b)	119	113

(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.

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

First Quarter of 2017	$119.1
Changes in Gross Margin:	
Retail Margins	53.8
Off-System Sales	5.5
Transmission Revenues	(4.0)
Other Revenues	1.8
Total Change in Gross Margin	57.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(64.8)
Depreciation and Amortization	(16.4)
Taxes Other Than Income Taxes	(10.5)
Interest and Investment Income	(2.1)
Carrying Costs Income	(1.2)
Allowance for Equity Funds Used During Construction	3.8
Non-Service Cost Components of Net Periodic Benefit Cost	6.0
Interest Expense	(0.1)
Total Change in Expenses and Other	(85.3)
Income Tax Expense	34.5
First Quarter of 2018	$125.4

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

- Retail Margins increased $54 million primarily due to the following:
  - A $39 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by a corresponding 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 $10 million increase in Texas weather-related usage primarily driven by a 125% increase in heating degree days partially offset by a 24% decrease in cooling degree days.
  - A $10 million increase in weather-normalized margins, primarily in the residential and commercial classes.
  - A $9 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 $7 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $6 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $4 million net increase in Ohio RSR revenues less associated amortizations.

  These increases were partially offset by:
  -

- A $21 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
- An $11 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues in Ohio. This decrease was partially offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- A $10 million decrease in margin for the Ohio Phase-In-Recovery Rider including associated amortizations.
- A $7 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.

- A $7 million decrease in Ohio revenues associated with smart grid riders. This decrease was partially offset by a corresponding decrease in various expenses below.
- Margins from Off-system Sales increased $6 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 $4 million primarily due to the following:
- An $11 million decrease mainly due to the 2018 provisions for customer refunds primarily due to Tax Reform. This decrease is offset in Income Tax Expense below.

This decrease was partially offset by:

- A $7 million increase due to recovery of increased transmission investment in ERCOT.

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

- Other Operation and Maintenance expenses increased $65 million primarily due to the following:
- A $44 million increase in 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.

These increases were partially offset by:

- A $9 million decrease in Ohio Energy Efficiency/Peak Demand Reduction expenses that were fully recovered in rate recovery riders/trackers within Retail Margins above.
- Depreciation and Amortization expenses increased $16 million primarily due to the following:
- A $7 million increase in depreciation expense due to an increase in depreciable base of transmission and distribution assets.
- A $6 million increase in recoverable DIR depreciation expense in Ohio. This increase was offset in Retail Margins above.
- A $5 million increase due to securitization amortizations related to Texas securitized transition funding. This increase was offset in Other Revenues above and in Interest Expense below.
- Taxes Other Than Income Taxes increased $11 million primarily due to the following:
- A $6 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- A $4 million increase in state excise taxes due to an increase in metered KWhs. This increase was offset in Retail Margins above.
- Allowance for Equity Funds Used During Construction increased $4 million 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 and by moving to a Medicare Advantage arrangement for post-65 retirees in the Non-UMWA OPEB plan. Additionally, the decrease was partially due to the implementation of ASU 2017-07 in 2018, which eliminated AEP's ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $35 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and a decrease in pretax book income.

AEP TRANSMISSION HOLDCO

	Three Months Ended March 31,	
AEP Transmission Holdco	2018	2017
	(in millions)	
Transmission Revenues	$205.5	$156.1
Other Operation and Maintenance	21.9	14.1
Depreciation and Amortization	31.8	24.6
Taxes Other Than Income Taxes	32.7	28.0
Operating Income	119.1	89.4
Interest and Investment Income	0.3	0.2
Allowance for Equity Funds Used During Construction	15.3	10.8
Non-Service Cost Components of Net Periodic Benefit Cost	0.7	0.1
Interest Expense	(21.1)	(17.3)
Income Before Income Tax Expense and Equity Earnings	114.3	83.2
Income Tax Expense	27.5	36.4
Equity Earnings of Unconsolidated Subsidiaries	18.0	26.0
Net Income	104.8	72.8
Net Income Attributable to Noncontrolling Interests	0.8	1.0
Earnings Attributable to AEP Common Shareholders	$104.0	$71.8

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	As of March 31,	
	2018	2017
	(in millions)	
Plant in Service	$5,912.8	$4,476.5
Construction Work in Progress	1,533.7	1,188.8
Accumulated Depreciation and Amortization	200.0	120.6
Total Transmission Property, Net	$7,246.5	$5,544.7

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First Quarter of 2018 Compared to First Quarter of 2017

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

First Quarter of 2017	$71.8
Changes in Transmission Revenues:	
Transmission Revenues	49.4
Total Change in Transmission Revenues	49.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.8)
Depreciation and Amortization	(7.2)
Taxes Other Than Income Taxes	(4.7)
Interest and Investment Income	0.1
Allowance for Equity Funds Used During Construction	4.5
Non-Service Cost Components of Net Periodic Pension Cost	0.6
Interest Expense	(3.8)
Total Change in Expenses and Other	(18.3)
Income Tax Expense	8.9
Equity Earnings of Unconsolidated Subsidiaries	(8.0)
Net Income Attributable to Noncontrolling Interests	0.2
First Quarter of 2018	$104.0

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

- Transmission Revenues increased $49 million primarily due to the following:
- Formula rate increases of $68 million driven by continued investment in transmission assets.

This increase was partially offset by:

- A $19 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset 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 $7 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $5 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $5 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $4 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense decreased $9 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, partially offset by an increase in pretax book income.
-

Equity Earnings of Unconsolidated Subsidiaries decreased $8 million primarily due to lower earnings at ETT resulting from decreased revenues driven by Tax Reform and by an ETT rate reduction that went into effect in March 2017, increased operating expenses, decreased AFUDC and increased interest expense.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended March 31, 2018	2017
	(in millions)	
Revenues	$505.1	$591.4
Fuel, Purchased Electricity and Other	408.8	405.2
Gross Margin	96.3	186.2
Other Operation and Maintenance	67.6	99.8
Gain on Sale of Merchant Generation Assets	—	(226.5)
Depreciation and Amortization	6.9	5.7
Taxes Other Than Income Taxes	3.2	2.0
Operating Income	18.6	305.2
Interest and Investment Income	2.5	2.2
Non-Service Cost Components of Net Periodic Benefit Cost	3.9	2.3
Interest Expense	(3.9)	(6.5)
Income Before Income Tax Expense	21.1	303.2
Income Tax Expense	3.0	117.0
Net Income	18.1	186.2
Net Loss Attributable to Noncontrolling Interests	(0.1)	—
Earnings Attributable to AEP Common Shareholders	$18.2	$186.2

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended March 31, 2018	2017
	(in millions of MWhs)	
Fuel Type:		
Coal	4	6
Natural Gas	—	2
Total MWhs	4	8

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

First Quarter of 2017	$186.2
Changes in Gross Margin:	
Generation	(53.6)
Retail, Trading and Marketing	(37.7)
Other	1.4
Total Change in Gross Margin	(89.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	32.2
Gain on Sale of Merchant Generation Assets	(226.5)
Depreciation and Amortization	(1.2)
Taxes Other Than Income Taxes	(1.2)
Interest and Investment Income	0.3
Non-Service Cost Components of Net Periodic Benefit Cost	1.6
Interest Expense	2.6
Total Change in Expenses and Other	(192.2)
Income Tax Expense	114.0
Net Loss Attributable to Noncontrolling Interests	0.1
First Quarter of 2018	$18.2

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, purchased electricity and certain cost of service for retail operations were as follows:

- Generation decreased $54 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets in 2017.
- Retail, Trading and Marketing decreased $38 million primarily due to reduced wholesale trading and marketing revenues, mark-to-market hedge losses and lower retail margins.

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

- Other Operation and Maintenance expenses decreased $32 million primarily due to the following:
  - A $21 million decrease in expenses due to the sale of certain merchant generation assets in 2017.
  - An $11 million decrease in expenses due to an impairment of certain merchant generation assets in 2017.
- Gain on Sale of Merchant Generation Assets decreased $227 million due to the sale of certain merchant generation assets in 2017.
- Income Tax Expense decreased $114 million primarily due to a reduction in pretax book income due to the gain on sale of certain merchant generation assets in 2017 and the change in corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform.

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CORPORATE AND OTHER

First Quarter of 2018 Compared to First Quarter of 2017

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $4 million in 2017 to a loss of $24 million in 2018. The loss in 2018 is primarily due to a $20 million impairment of an equity investment and related assets and a $12 million increase in interest expense partially offset by a $9 million decrease in general corporate expenses.

AEP SYSTEM INCOME TAXES

First Quarter of 2018 Compared to First Quarter of 2017

Income Tax Expense decreased $241 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, the amortization of excess accumulated deferred income taxes associated with certain depreciable property in 2018 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

	March 31, 2018		December 31, 2017	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$21,461.0	50.3 %	$21,173.3	51.5 %
Short-term Debt	2,658.8	6.2	1,638.6	4.0
Total Debt	24,119.8	56.5	22,811.9	55.5
AEP Common Equity	18,483.3	43.4	18,287.0	44.4
Noncontrolling Interests	28.3	0.1	26.6	0.1
Total Debt and Equity Capitalization	$42,631.4	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 56.5% as of March 31, 2018 primarily due to an increase in short-term 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 March 31, 2018, AEP had a $3 billion revolving credit facility commitment to support its operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of March 31, 2018, available liquidity was approximately $1.3 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	183.4	
Total Liquidity Sources	3,183.4	
Less: AEP Commercial Paper Outstanding	1,886.2	
Net Available Liquidity	$ 1,297.2	

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 three months of 2018 was $2.2 billion. The weighted-average interest rate for AEP's commercial paper during 2018 was 2.07%.

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. In March 2018, one of the uncommitted credit facilities was reduced by $40 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2018 was $81 million with maturities ranging from May 2018 to March 2019.

Securitized Accounts Receivables

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in June 2019.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of March 31, 2018, this contractually-defined percentage was 54.8%. Nonperformance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.62 per share in April 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.

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.

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$412.6	$403.5
Net Cash Flows from Operating Activities	802.2	806.8
Net Cash Flows from (Used for) Investing Activities	(1,927.8)	776.2
Net Cash Flows from (Used for) Financing Activities	1,029.5	(1,687.1)
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(96.1)	(104.1)
Cash, Cash Equivalents and Restricted Cash at End of Period	$316.5	$299.4

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Operating Activities

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Net Income	$456.7	$594.2
Non-Cash Adjustments to Net Income (a)	623.7	405.5
Mark-to-Market of Risk Management Contracts	(0.7)	6.0
Property Taxes	(63.7)	(44.4)
Deferred Fuel Over/Under Recovery, Net	(61.2)	19.3
Recovery of Ohio Capacity Costs, Net	18.0	30.2
Provision for Refund - Global Settlement, Net	(5.4)	—
Change in Other Noncurrent Assets	(59.8)	(99.1)
Change in Other Noncurrent Liabilities	133.3	45.0
Change in Certain Components of Working Capital	(238.7)	(149.9)
Net Cash Flows from Operating Activities	$802.2	$806.8

(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 and Gain on Sale of Merchant Generation Assets.

Net Cash Flows from Operating Activities decreased by $5 million primarily due to the following:

- An $89 million decrease in cash from Changes in Certain Components of Working Capital. This decrease is primarily due to changes in accrued federal taxes and timing of receivables and payables, partially offset by lower employee-related payments.
- An $81 million decrease in cash from Deferred Fuel Over/Under Recovery, Net, primarily due to fluctuations of fuel and purchase power costs at APCo.

These decreases in cash were partially offset by:

- An $88 million increase in Change in Other Noncurrent Liabilities primarily due to increased Accumulated Provisions for Rate Refunds as a result of Tax Reform.
- An $81 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for additional information.

Investing Activities

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Construction Expenditures	$(1,905.8)	$(1,365.8)
Acquisitions of Nuclear Fuel	(23.8)	(3.7)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6
Other	1.8	(13.9)
Net Cash Flows from (Used for) Investing Activities	$(1,927.8)	$776.2

Net Cash Flows from (Used for) Investing Activities decreased by $2.7 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 $540 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $343 million and AEP Transmission Holdco of $168 million.

Financing Activities

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Issuance of Common Stock, Net	$32.2	$—
Issuance/Retirement of Debt, Net	1,317.2	(1,336.4)
Dividends Paid on Common Stock	(306.1)	(291.4)
Other	(13.8)	(59.3)
Net Cash Flows from (Used for) Financing Activities	$1,029.5	$(1,687.1)

Net Cash Flows from (Used for) Financing Activities increased by $2.7 billion primarily due to the following:

- A $1.2 billion increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 12 - Financing Activities for additional information.
- A $758 million increase in cash due to increased issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $698 million increase in cash due to decreased retirements of long-term debt. See Note 12 - Financing Activities for additional information.
- A $32 million increase in cash due to increased proceeds from issuances of common stock.

These increases in cash were partially offset by:

- A $15 million decrease due to increased common stock dividend payments primarily due to increased dividends per share from 2017 to 2018.

In April 2018, AEP Texas retired $30 million of 5.89% Senior Unsecured Notes due in 2018.

In April 2018, I&M retired $2 million of Notes Payable related to DCC Fuel.

OFF-BALANCE SHEET ARRANGEMENTS

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

	March 31, 2018	December 31, 2017
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$738.4	$ 738.4
Railcars Maximum Potential Loss from Lease Agreement	15.4	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 major 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)
Three Months Ended March 31, 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	(30.5)	(1.1)	(9.2)	(40.8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	6.1	6.1
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	(22.4)	(22.4)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	5.8	34.8	—	40.6
Total MTM Risk Management Contract Net Assets (Liabilities) as of March 31, 2018	$17.4	$ (97.6)	$ 138.4	58.2
Commodity Cash Flow Hedge Contracts				(33.4)
Fair Value Hedge Contracts				(20.6)
Collateral Deposits				16.8
Total MTM Derivative Contract Net Assets as of March 31, 2018				$21.0

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

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

Credit Risk

Credit risk is mitigated in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses Moody’s Investors Service Inc., S&P Global Inc. and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of March 31, 2018, credit exposure net of collateral to sub investment grade counterparties was approximately 7%, 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 March 31, 2018, the following table approximates AEP’s counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

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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	$502.5	$ —	$ 502.5	3	$ 273.6
Split Rating	3.5	—	3.5	1	3.5
Noninvestment Grade	0.8	0.8	—	—	—
No External Ratings:					
Internal Investment Grade	114.7	—	114.7	3	72.3
Internal Noninvestment Grade	57.3	10.5	46.8	2	30.6
Total as of March 31, 2018	$678.8	$ 11.3	$ 667.5		

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of March 31, 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

Three Months Ended March 31, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.2	$1.8	$ 0.4	$0.1	$0.2	$0.5	$ 0.2	$0.1

VaR Model
Non-Trading Portfolio

Three Months Ended March 31, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$1.4	$6.9	$ 2.8	$1.0	$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 three months ended March 31, 2018 and 2017, a 100 basis point change in the benchmark rate on AEP’s variable rate debt would impact pre-tax interest expense annually by $25 million and $35 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended March 31, 2018	2017
REVENUES		
Vertically Integrated Utilities	$2,381.5	$ 2,269.8
Transmission and Distribution Utilities	1,141.2	1,066.4
Generation & Marketing	477.5	558.8
Other Revenues	48.1	38.3
TOTAL REVENUES	4,048.3	3,933.3
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	501.8	635.6
Purchased Electricity for Resale	990.3	769.6
Other Operation	726.4	623.7
Maintenance	298.5	303.5
Gain on Sale of Merchant Generation Assets	—	(226.5)
Depreciation and Amortization	539.7	481.9
Taxes Other Than Income Taxes	285.6	259.8
TOTAL EXPENSES	3,342.3	2,847.6
OPERATING INCOME	706.0	1,085.7
Other Income (Expense):		
Interest and Investment Income	2.1	8.0
Carrying Costs Income	3.4	5.9
Allowance for Equity Funds Used During Construction	30.7	21.2
Non-Service Cost Components of Net Periodic Benefit Cost	32.0	11.4
Interest Expense	(234.0)	(221.8)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	540.2	910.4
Income Tax Expense	102.0	343.2
Equity Earnings of Unconsolidated Subsidiaries	18.5	27.0
NET INCOME	456.7	594.2
Net Income Attributable to Noncontrolling Interests	2.3	2.0
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$454.4	$ 592.2
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	492,267,404	491,712,042

TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.92	$ 1.20
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	493,127,300	492,031,975
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$0.92	$ 1.20
CASH DIVIDENDS DECLARED PER SHARE	$0.62	$ 0.59

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income	$456.7	$594.2
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.7 and $(8.7) in 2018 and 2017, Respectively	2.7	(16.1)
Securities Available for Sale, Net of Tax of $0 and $0.6 in 2018 and 2017, Respectively	—	1.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.4) and $0.1 in 2018 and 2017, Respectively	(1.4)	0.2
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	1.3	(14.7)
TOTAL COMPREHENSIVE INCOME	458.0	579.5
Total Comprehensive Income Attributable to Noncontrolling Interests	2.3	2.0
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$455.7	$577.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other Comprehensive Income (Loss)		
	Shares	Amount	Paid-in Capital	Retained Earnings		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				(290.3)		(1.1)	(291.4)
Other Changes in Equity			2.9			0.6	3.5
Net Income				592.2		2.0	594.2
Other Comprehensive Loss					(14.7)		(14.7)
TOTAL EQUITY – MARCH 31, 2017	512.0	$3,328.3	$6,335.5	$8,194.3	$ (171.0)	$ 24.6	$17,711.7
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	0.5	3.3	28.9				32.2
Common Stock Dividends				(305.5)		(0.6)	(306.1)
Other Changes in Equity			16.9				16.9
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				454.4		2.3	456.7
Other Comprehensive Income					1.3		1.3
TOTAL EQUITY – MARCH 31, 2018	512.7	$3,332.7	$6,444.5	$8,801.5	$ (95.4)	$ 28.3	$18,511.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$183.4	$214.6
Restricted Cash		
(March 31, 2018 and December 31, 2017 Amounts Relate to Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding)	133.1	198.0
Other Temporary Investments		
(March 31, 2018 and December 31, 2017 Amounts Include $155.8 and $155.4, Respectively, Related to EIS, Transource Energy and Sabine)	167.9	161.7
Accounts Receivable:		
Customers	635.6	643.9
Accrued Unbilled Revenues	213.4	230.2
Pledged Accounts Receivable – AEP Credit	975.3	954.2
Miscellaneous	66.5	101.2
Allowance for Uncollectible Accounts	(39.3)	(38.5)
Total Accounts Receivable	1,851.5	1,891.0
Fuel	359.6	387.7
Materials and Supplies	563.2	565.5
Risk Management Assets	89.6	126.2
Regulatory Asset for Under-Recovered Fuel Costs	352.3	292.5
Margin Deposits	154.2	105.5
Prepayments and Other Current Assets	280.2	310.4
TOTAL CURRENT ASSETS	4,135.0	4,253.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	20,824.0	20,760.5
Transmission	19,239.9	18,972.5
Distribution	20,160.5	19,868.5
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	3,812.5	3,706.3
Construction Work in Progress	4,759.4	4,120.7
Total Property, Plant and Equipment	68,796.3	67,428.5
Accumulated Depreciation and Amortization	17,431.2	17,167.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	51,365.1	50,261.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,516.9	3,587.6
Securitized Assets	1,146.6	1,211.2
Spent Nuclear Fuel and Decommissioning Trusts	2,510.6	2,527.6
Goodwill	52.5	52.5
Long-term Risk Management Assets	271.2	282.1
Deferred Charges and Other Noncurrent Assets	2,611.6	2,553.5

TOTAL OTHER NONCURRENT ASSETS	10,109.4	10,214.5
TOTAL ASSETS	$65,609.5	$ 64,729.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable	$ 1,449.6	$ 2,065.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	718.0
Other Short-term Debt	1,908.8	920.6
Total Short-term Debt	2,658.8	1,638.6
Long-term Debt Due Within One Year (March 31, 2018 and December 31, 2017 Amounts Include $406.5 and $406.9, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,616.1	1,753.7
Risk Management Liabilities	57.1	61.6
Customer Deposits	365.5	357.0
Accrued Taxes	1,081.4	1,115.5
Accrued Interest	273.1	234.5
Regulatory Liability for Over-Recovered Fuel Costs	9.8	11.9
Other Current Liabilities	960.0	1,033.2
TOTAL CURRENT LIABILITIES	9,471.4	8,271.3
NONCURRENT LIABILITIES		
Long-term Debt (March 31, 2018 and December 31, 2017 Amounts Include $1,253 and $1,410.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	18,844.9	19,419.6
Long-term Risk Management Liabilities	282.7	322.0
Deferred Income Taxes	6,943.9	6,813.9
Regulatory Liabilities and Deferred Investment Tax Credits	8,394.5	8,422.3
Asset Retirement Obligations	1,933.7	1,925.5
Employee Benefits and Pension Obligations	330.9	398.1
Deferred Credits and Other Noncurrent Liabilities	808.2	830.9
TOTAL NONCURRENT LIABILITIES	37,538.8	38,132.3
TOTAL LIABILITIES	47,010.2	46,403.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	70.7	—
Contingently Redeemable Performance Share Awards	17.0	11.9
TOTAL MEZZANINE EQUITY	87.7	11.9

EQUITY

Common Stock – Par Value – $6.50 Per Share:

	2018	2017		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	512,716,170	512,210,644		
(20,204,160 and 20,205,046 Shares were Held in Treasury as of March 31, 2018 and December 31, 2017, Respectively)			3,332.7	3,329.4
Paid-in Capital			6,444.5	6,398.7
Retained Earnings			8,801.5	8,626.7
Accumulated Other Comprehensive Income (Loss)			(95.4)	(67.8)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			18,483.3	18,287.0
Noncontrolling Interests			28.3	26.6
TOTAL EQUITY			18,511.6	18,313.6
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$65,609.5	$ 64,729.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31, 2018		2017	
OPERATING ACTIVITIES				
Net Income	$ 456.7		$ 594.2	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	539.7		481.9	
Deferred Income Taxes	87.3		136.2	
Allowance for Equity Funds Used During Construction	(30.7	)	(21.2	)
Mark-to-Market of Risk Management Contracts	(0.7	)	6.0	
Amortization of Nuclear Fuel	27.4		35.1	
Property Taxes	(63.7	)	(44.4	)
Deferred Fuel Over/Under-Recovery, Net	(61.2	)	19.3	
Gain on Sale of Merchant Generation Assets	—		(226.5	)
Recovery of Ohio Capacity Costs	18.0		30.2	
Provision for Refund - Global Settlement, Net	(5.4	)	—	
Change in Other Noncurrent Assets	(59.8	)	(99.1	)
Change in Other Noncurrent Liabilities	133.3		45.0	
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	39.7		235.8	
Fuel, Materials and Supplies	28.5		13.4	
Accounts Payable	(129.3	)	(250.7	)
Accrued Taxes, Net	(74.3	)	186.8	
Other Current Assets	(40.1	)	(45.9	)
Other Current Liabilities	(63.2	)	(289.3	)
Net Cash Flows from Operating Activities	802.2		806.8	
INVESTING ACTIVITIES				
Construction Expenditures	(1,905.8	)	(1,365.8	)
Purchases of Investment Securities	(525.9	)	(506.0	)

Sales of Investment Securities	508.6	487.9
Acquisitions of Nuclear Fuel	(23.8)	(3.7)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6
Other Investing Activities	19.1	4.2
Net Cash Flows from (Used for) Investing Activities	(1,927.8)	776.2
FINANCING ACTIVITIES		
Issuance of Common Stock, Net	32.2	—
Issuance of Long-term Debt	841.0	82.9
Commercial Paper and Credit Facility Borrowings	205.6	—
Change in Short-term Debt, Net	814.6	(177.0)
Retirement of Long-term Debt	(544.0)	(1,242.3)
Make Whole Payment on Extinguishment of Long-term Debt	—	(44.9)
Principal Payments for Capital Lease Obligations	(16.8)	(16.6)
Dividends Paid on Common Stock	(306.1)	(291.4)
Other Financing Activities	3.0	2.2
Net Cash Flows from (Used for) Financing Activities	1,029.5	(1,687.1)
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(96.1)	(104.1)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	412.6	403.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 316.5	$ 299.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 188.0	$ 205.9
Net Cash Paid (Received) for Income Taxes	(0.9)	(88.8)
Noncash Acquisitions Under Capital Leases	21.4	11.4
Construction Expenditures Included in Current Liabilities as of March 31,	799.9	515.6
Noncash Contribution of Assets by Noncontrolling	84.0	—

Interest		
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.1	1.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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AEP TEXAS INC.
AND SUBSIDIARIES

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AEP TEXAS INC. AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2018	2017
	(in millions of KWhs)	
Retail:		
Residential	2,664	2,201
Commercial	2,312	2,325
Industrial	1,960	1,907
Miscellaneous	122	128
Total Retail	7,058	6,561

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Actual – Heating (a)	230	102
Normal – Heating (b)	191	195
Actual – Cooling (c)	196	258
Normal – Cooling (b)	119	113

(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.

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

First Quarter of 2017	$ 33.3
Changes in Gross Margin:	
Retail Margins	18.6
Off-system Sales	(1.6)
Transmission Revenues	2.4
Other Revenues	2.7
Total Change in Gross Margin	22.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(11.3)
Depreciation and Amortization	(7.2)
Taxes Other Than Income Taxes	(4.1)
Interest Income	(0.5)
Allowance for Equity Funds Used During Construction	3.7
Non-Service Cost Components of Net Periodic Benefit Cost	2.2
Interest Expense	—
Total Change in Expenses and Other	(17.2)
Income Tax Expense	8.6
First Quarter of 2018	$ 46.8

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

- Retail Margins increased $19 million primarily due to the following:
  - A $10 million increase in weather-related usage primarily driven by a 125% increase in heating degree days partially offset by a 24% decrease in cooling degree days.
  - A $9 million increase in revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $7 million increase in revenues associated with the Distribution Cost Recovery Factor revenue rider.

  These increases were partially offset by:
  - A $5 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
- Transmission Revenues increased by $2 million primarily due to the following:
  - A $7 million increase due to recovery of increased transmission investment in ERCOT.

  This increase was partially offset by:
  - A $5 million decrease due to the 2018 provisions for customer refunds primarily due to Tax Reform. This decrease is offset in Income Tax Expense below.
- Other Revenues increased $3 million primarily due to securitization revenue related to Transition Funding. This increase was offset in Depreciation and Amortization and Interest Expense below.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to an increase in ERCOT transmission expenses. This increase was partially offset by an increase in Retail Margins above.

- Depreciation and Amortization expenses increased $7 million primarily due to securitization amortizations related to Transition Funding. This increase was offset in Other Revenues above and in Interest Expense below.
- Taxes Other Than Income Taxes increased $4 million primarily due to increased property taxes as a result of additional capital investment and increased tax rates.
- Interest Expense was unchanged primarily due to:
- A $3 million decrease in securitization assets related to Transition Funding. This decrease was offset above in Other Revenues and in Depreciation and Amortization.
- A $2 million decrease due to higher debt component of AFUDC from increased transmission projects.

These decreases were offset by:

- A $5 million increase in interest due to the issuance of long-term debt in September 2017.
- Allowance for Equity Funds Used During Construction increased $4 million due to increased transmission projects.
- Income Tax Expense decreased $9 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and amortization of excess accumulated deferred income taxes associated with certain depreciable property, partially offset by an increase in pretax book income.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Electric Transmission and Distribution	$352.4	$328.9
Sales to AEP Affiliates	18.2	14.1
Other Revenues	1.0	0.6
TOTAL REVENUES	371.6	343.6
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	8.9	3.0
Other Operation	117.0	108.8
Maintenance	21.5	18.4
Depreciation and Amortization	110.0	102.8
Taxes Other Than Income Taxes	32.4	28.3
TOTAL EXPENSES	289.8	261.3
OPERATING INCOME	81.8	82.3
Other Income (Expense):		
Interest Income	0.5	1.0
Allowance for Equity Funds Used During Construction	5.5	1.8
Non-Service Cost Components of Net Periodic Benefit Cost	3.1	0.9
Interest Expense	(35.0)	(35.0)
INCOME BEFORE INCOME TAX EXPENSE	55.9	51.0
Income Tax Expense	9.1	17.7
NET INCOME	$46.8	$33.3

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income	$46.8	$33.3
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 in 2018 and 2017, Respectively	0.2	0.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 in 2018 and 2017, Respectively	0.1	0.1
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3
TOTAL COMPREHENSIVE INCOME	$47.1	$33.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$857.9	$814.1	$ (14.9)	$1,657.1
Capital Contribution from Parent	200.0			200.0
Net Income		33.3		33.3
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2017	$1,057.9	$847.4	$ (14.6)	$1,890.7
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$1,057.9	$1,124.6	$ (12.6)	$2,169.9
Capital Contribution from Parent	100.0			100.0
ASU 2018-02 Adoption		1.8	(2.7)	(0.9)
Net Income		46.8		46.8
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	$1,157.9	$1,173.2	$ (15.0)	$2,316.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$0.1	$2.0
Restricted Cash for Securitized Transition Funding	107.1	155.2
Advances to Affiliates	8.1	111.9
Accounts Receivable:		
Customers	117.7	105.3
Affiliated Companies	9.0	12.3
Accrued Unbilled Revenues	65.7	75.8
Miscellaneous	0.3	1.3
Allowance for Uncollectible Accounts	(0.5)	(0.7)
Total Accounts Receivable	192.2	194.0
Fuel	6.4	3.6
Materials and Supplies	49.4	52.0
Risk Management Assets	0.3	0.5
Accrued Tax Benefits	66.4	41.0
Prepayments and Other Current Assets	5.8	3.6
TOTAL CURRENT ASSETS	435.8	563.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	350.9	350.7
Transmission	3,097.6	3,053.6
Distribution	3,854.2	3,718.6
Other Property, Plant and Equipment	475.4	461.0
Construction Work in Progress	951.6	835.7
Total Property, Plant and Equipment	8,729.7	8,419.6
Accumulated Depreciation and Amortization	1,617.4	1,594.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,112.3	6,825.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	379.4	378.7
Securitized Transition Assets (March 31, 2018 and December 31, 2017 Amounts Include $819.2 and $869.5, Respectively, Related to Transition Funding)	838.9	891.2
Deferred Charges and Other Noncurrent Assets	134.0	114.8
TOTAL OTHER NONCURRENT ASSETS	1,352.3	1,384.7
TOTAL ASSETS	$8,900.4	$8,773.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$232.7	$—
Accounts Payable:		
General	209.0	379.4
Affiliated Companies	22.7	30.2
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2018 and December 31, 2017 Amounts Include $243.1 and $236.1, Respectively, Related to Transition Funding)	273.1	266.1
Accrued Taxes	89.7	77.2
Accrued Interest (March 31, 2018 and December 31, 2017 Amounts Include $10.2 and $15.9, Respectively, Related to Transition Funding)	48.0	42.2
Other Current Liabilities	70.7	76.4
TOTAL CURRENT LIABILITIES	945.9	871.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (March 31, 2018 and December 31, 2017 Amounts Include $686.8 and $790.1, Respectively, Related to Transition Funding)	3,280.2	3,383.2
Deferred Income Taxes	913.1	913.1
Regulatory Liabilities and Deferred Investment Tax Credits	1,320.2	1,320.5
Oklaunion Purchase Power Agreement	51.8	52.0
Deferred Credits and Other Noncurrent Liabilities	73.1	63.4
TOTAL NONCURRENT LIABILITIES	5,638.4	5,732.2
TOTAL LIABILITIES	6,584.3	6,603.7
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Paid-in Capital	1,157.9	1,057.9
Retained Earnings	1,173.2	1,124.6
Accumulated Other Comprehensive Income (Loss)	(15.0)	(12.6)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,316.1	2,169.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER’S EQUITY	$8,900.4	$8,773.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$46.8	$33.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	110.0	102.8
Deferred Income Taxes	(4.4)	40.8
Allowance for Equity Funds Used During Construction	(5.5)	(1.8)
Mark-to-Market of Risk Management Contracts	0.2	0.1
Property Taxes	(56.1)	(46.2)
Change in Other Noncurrent Assets	(12.7)	(12.7)
Change in Other Noncurrent Liabilities	6.5	4.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	1.8	3.7
Fuel, Materials and Supplies	(0.2)	0.4
Accounts Payable	(25.9)	(13.4)
Accrued Taxes, Net	25.2	(3.5)
Other Current Assets	(1.6)	(0.3)
Other Current Liabilities	(5.1)	(25.9)
Net Cash Flows from Operating Activities	79.0	82.1
INVESTING ACTIVITIES		
Construction Expenditures	(481.6)	(200.2)
Change in Advances to Affiliates, Net	103.8	0.3
Other Investing Activities	13.4	4.6
Net Cash Flows Used for Investing Activities	(364.4)	(195.3)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100.0	200.0
Change in Advances from Affiliates, Net	232.7	(43.0)
Retirement of Long-term Debt – Nonaffiliated	(96.5)	(89.9)
Principal Payments for Capital Lease Obligations	(1.1)	(0.9)
Other Financing Activities	0.3	0.6
Net Cash Flows from Financing Activities	235.4	66.8
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding	(50.0)	(46.4)
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at Beginning of Period	157.2	146.9
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at End of Period	$107.2	$100.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$27.8	$33.7
Noncash Acquisitions Under Capital Leases	4.0	2.0

Construction Expenditures Included in Current Liabilities as of March 31,	169.3	65.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AEP TRANSMISSION COMPANY, LLC
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of March 31,	
	2018	2017
	(in millions)	
Plant In Service	$5,595.4	$4,162.3
Construction Work in Progress	1,512.6	1,184.4
Accumulated Depreciation and Amortization	192.7	117.8
Total Transmission Property, Net	$6,915.3	$5,228.9

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

First Quarter of 2017	$57.0
Changes in Transmission Revenues:	
Transmission Revenues	40.8
Total Change in Transmission Revenues	40.8
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.0)
Depreciation and Amortization	(7.3)
Taxes Other Than Income Taxes	(4.3)
Interest Income	0.2
Allowance for Equity Funds Used During Construction	4.4
Interest Expense	(3.9)
Total Change in Expenses and Other	(17.9)
Income Tax Expense	6.0
First Quarter of 2018	$85.9

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

- Transmission Revenues increased $41 million primarily due to the following:
- Formula rate increases of $60 million driven by continued investment in transmission assets.

This increase was partially offset by:

- A $19 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $7 million primarily due to a higher depreciable base.

- Taxes Other Than Income Taxes increased $4 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $4 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $4 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense decreased $6 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, partially offset by an increase in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Transmission Revenues	$31.3	$19.2
Sales to AEP Affiliates	162.1	133.4
Other Revenues	0.1	0.1
TOTAL REVENUES	193.5	152.7
EXPENSES		
Other Operation	16.6	9.1
Maintenance	2.6	3.1
Depreciation and Amortization	30.6	23.3
Taxes Other Than Income Taxes	31.1	26.8
TOTAL EXPENSES	80.9	62.3
OPERATING INCOME	112.6	90.4
Other Income (Expense):		
Interest Income	0.4	0.2
Allowance for Equity Funds Used During Construction	15.3	10.9
Interest Expense	(19.9)	(16.0)
INCOME BEFORE INCOME TAX EXPENSE	108.4	85.5
Income Tax Expense	22.5	28.5
NET INCOME	$85.9	$57.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total Member's Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	$ 1,455.0	$ 502.6	$ 1,957.6
Capital Contributions from Member	125.5		125.5
Net Income		57.0	57.0
TOTAL MEMBER'S EQUITY – MARCH 31, 2017	$ 1,580.5	$ 559.6	$ 2,140.1
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	$ 1,816.6	$ 788.7	$ 2,605.3
Capital Contributions from Member	65.0		65.0
Net Income		85.9	85.9
TOTAL MEMBER'S EQUITY – MARCH 31, 2018	$ 1,881.6	$ 874.6	$ 2,756.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Advances to Affiliates	$32.1	$ 146.3
Accounts Receivable:		
Customers	20.5	19.1
Affiliated Companies	102.0	93.2
Miscellaneous	1.2	1.3
Total Accounts Receivable	123.7	113.6
Materials and Supplies	15.5	13.6
Accrued Tax Benefits	40.1	46.6
Prepayments and Other Current Assets	2.8	7.6
TOTAL CURRENT ASSETS	214.2	327.7
TRANSMISSION PROPERTY		
Transmission Property	5,458.3	5,336.1
Other Property, Plant and Equipment	137.1	131.4
Construction Work in Progress	1,512.6	1,312.7
Total Transmission Property	7,108.0	6,780.2
Accumulated Depreciation and Amortization	192.7	170.4
TOTAL TRANSMISSION PROPERTY – NET	6,915.3	6,609.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	8.9	11.7
Deferred Property Taxes	100.5	117.8
Deferred Charges and Other Noncurrent Assets	1.0	1.1
TOTAL OTHER NONCURRENT ASSETS	110.4	130.6
TOTAL ASSETS	$7,239.9	$ 7,068.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$282.1	$15.7
Accounts Payable:		
General	210.5	473.2
Affiliated Companies	41.3	52.9
Long-term Debt Due Within One Year – Nonaffiliated	50.0	50.0
Accrued Taxes	185.3	225.4
Accrued Interest	38.3	15.0
Provision for Refund	47.6	—
Other Current Liabilities	2.6	4.1
TOTAL CURRENT LIABILITIES	857.7	836.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,500.7	2,500.4
Deferred Income Taxes	621.3	601.7
Regulatory Liabilities	497.2	493.7
Deferred Credits and Other Noncurrent Liabilities	6.8	30.7
TOTAL NONCURRENT LIABILITIES	3,626.0	3,626.5
TOTAL LIABILITIES	4,483.7	4,462.8
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	1,881.6	1,816.6
Retained Earnings	874.6	788.7
TOTAL MEMBER'S EQUITY	2,756.2	2,605.3
TOTAL LIABILITIES AND MEMBER'S EQUITY	$7,239.9	$7,068.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,					
	2018			2017		
OPERATING ACTIVITIES						
Net Income	$	85.9		$	57.0	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	30.6			23.3		
Deferred Income Taxes	15.7			74.1		
Allowance for Equity Funds Used During Construction	(15.3		)	(10.9		)
Property Taxes	17.3			16.8		
Change in Other Noncurrent Assets	2.7			2.2		
Change in Other Noncurrent Liabilities	23.9			8.3		
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	(10.1		)	(39.0		)
Materials and Supplies	(1.9		)	(3.8		)
Accounts Payable	(12.3		)	(8.2		)
Accrued Taxes, Net	(33.6		)	(79.1		)
Accrued Interest	23.3			17.6		
Other Current Assets	0.3			0.2		
Other Current Liabilities	0.6			—		
Net Cash Flows from Operating Activities	127.1			58.5		
INVESTING ACTIVITIES						
Construction Expenditures	(571.8		)	(390.4		)
Change in Advances to Affiliates, Net	114.2			56.9		
Acquisitions of Assets	(1.8		)	(0.6		)
Other Investing Activities	1.0			—		
Net Cash Flows Used for Investing Activities	(458.4		)	(334.1		)
FINANCING ACTIVITIES						
Capital Contributions from Member	65.0			125.5		
	266.4			150.9		

Change in Advances from Affiliates, Net		
Other Financing Activities	(0.1)	(0.8)
Net Cash Flows from Financing Activities	331.3	275.6
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Net Cash Paid (Received) for Income Taxes	$ —	$ (0.6)
Construction Expenditures Included in Current Liabilities as of March 31,	210.6	189.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2018	2017
	(in millions of KWhs)	
Retail:		
Residential	3,845	3,250
Commercial	1,694	1,591
Industrial	2,377	2,299
Miscellaneous	224	210
Total Retail	8,140	7,350
Wholesale	495	806
Total KWhs	8,635	8,156

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Actual – Heating (a)	1,389	955
Normal – Heating (b)	1,317	1,328
Actual – Cooling (c)	8	2
Normal – Cooling (b)	7	7

(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.

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

First Quarter of 2017	$ 110.6
Changes in Gross Margin:	
Retail Margins	15.0
Off-system Sales	(0.2)
Transmission Revenues	(1.9)
Other Revenues	(2.2)
Total Change in Gross Margin	10.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(25.1)
Depreciation and Amortization	(7.9)
Taxes Other Than Income Taxes	(3.6)
Carrying Costs Income	0.2
Allowance for Equity Funds Used During Construction	1.1
Non-Service Cost Components of Net Periodic Benefit Cost	3.2
Interest Expense	0.7
Total Change in Expenses and Other	(31.4)
Income Tax Expense	35.6
First Quarter of 2018	$ 125.5

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

- Retail Margins increased $15 million primarily due to the following:
- A $50 million increase in weather-related usage primarily due to a 45% increase in heating degree days.
- An $11 million increase primarily due to increases from rate riders in Virginia. This increase is partially offset by a corresponding increase in Other Operation and Maintenance expenses.

These increases were partially offset by:

- A $32 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
- A $5 million decrease in weather-normalized margins occurring primarily in the residential and industrial classes.
- A $4 million decrease due to increased fuel and other variable production costs not recovered through fuel or other trackers.

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

- Other Operation and Maintenance expenses increased $25 million primarily due to the following:
  - A $12 million increase in recoverable PJM transmission expenses. This increase is offset within Retail Margins above.
  - A $5 million increase in estimated expense for claims related to asbestos exposure.
  - A $4 million increase in employee-related expenses.
- Depreciation and Amortization expenses increased $8 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $4 million primarily due to the following:
  - A $2 million increase in property taxes driven by an increase in utility plant.
  - A $2 million increase in state gross receipts tax due to a prior period refund.
- Non-Service Cost Components of Net Periodic Cost decreased $3 million primarily due to favorable asset returns for the funded Pension and OPEB plans and by moving to a Medicare Advantage arrangement for post-65 retirees in the Non-UMWA OPEB plan. Additionally, the decrease was partially due to the implementation of ASU 2017-07 in 2018, which eliminated APCo’s ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $36 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.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Electric Generation, Transmission and Distribution	$767.5	$745.0
Sales to AEP Affiliates	49.4	42.4
Other Revenues	3.5	5.4
TOTAL REVENUES	820.4	792.8
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	69.0	167.2
Purchased Electricity for Resale	205.9	90.8
Other Operation	138.2	113.9
Maintenance	72.0	71.2
Depreciation and Amortization	108.5	100.6
Taxes Other Than Income Taxes	33.8	30.2
TOTAL EXPENSES	627.4	573.9
OPERATING INCOME	193.0	218.9
Other Income (Expense):		
Interest Income	0.3	0.3
Carrying Costs Income	0.5	0.3
Allowance for Equity Funds Used During Construction	2.6	1.5
Non-Service Cost Components of Net Periodic Benefit Cost	4.5	1.3
Interest Expense	(47.4)	(48.1)
INCOME BEFORE INCOME TAX EXPENSE	153.5	174.2
Income Tax Expense	28.0	63.6
NET INCOME	$125.5	$110.6

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

See Condensed Notes to Condensed

Financial Statements of Registrants beginning on page 120.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income	$125.5	$110.6
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) in 2018 and 2017, Respectively	(0.2)	(0.2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.2) in 2018 and 2017, Respectively	(0.8)	(0.3)
TOTAL OTHER COMPREHENSIVE LOSS	(1.0)	(0.5)
TOTAL COMPREHENSIVE INCOME	$124.5	$110.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 260.4	$ 1,828.7	$ 1,502.8	$ (8.4)	$ 3,583.5
Common Stock Dividends			(30.0)		(30.0)
Net Income			110.6		110.6
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2017	$ 260.4	$ 1,828.7	$ 1,583.4	$ (8.9)	$ 3,663.6
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 260.4	$ 1,828.7	$ 1,714.1	$ 1.3	$ 3,804.5
Common Stock Dividends			(40.0)		(40.0)
ASU 2018-02 Adoption			0.1	0.3	0.4
Net Income			125.5		125.5
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	$ 260.4	$ 1,828.7	$ 1,799.7	$ 0.6	$ 3,889.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.2	$ 2.9
Restricted Cash for Securitized Funding	10.1	16.3
Advances to Affiliates	23.5	23.5
Accounts Receivable:		
Customers	137.9	123.1
Affiliated Companies	67.6	69.3
Accrued Unbilled Revenues	75.1	74.1
Miscellaneous	1.0	1.1
Allowance for Uncollectible Accounts	(3.5)	(3.7)
Total Accounts Receivable	278.1	263.9
Fuel	72.1	89.3
Materials and Supplies	97.4	99.5
Risk Management Assets	8.0	24.9
Regulatory Asset for Under-Recovered Fuel Costs	179.5	88.8
Margin Deposits	32.1	14.4
Prepayments and Other Current Assets	11.2	12.7
TOTAL CURRENT ASSETS	713.2	636.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,466.9	6,446.9
Transmission	3,032.5	3,019.9
Distribution	3,795.8	3,763.8
Other Property, Plant and Equipment	440.2	427.9
Construction Work in Progress	558.8	483.0
Total Property, Plant and Equipment	14,294.2	14,141.5
Accumulated Depreciation and Amortization	3,956.8	3,896.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,337.4	10,245.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	552.3	573.9
Securitized Assets	276.4	282.3
Long-term Risk Management Assets	2.6	1.1
Deferred Charges and Other Noncurrent Assets	195.1	190.0
TOTAL OTHER NONCURRENT ASSETS	1,026.4	1,047.3
TOTAL ASSETS	$ 12,077.0	$ 11,928.6

See
Condensed
Notes to

Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$245.9	$ 186.0
Accounts Payable:		
General	218.1	264.9
Affiliated Companies	88.1	92.7
Long-term Debt Due Within One Year – Nonaffiliated	249.5	249.2
Risk Management Liabilities	0.6	1.3
Customer Deposits	86.5	86.1
Accrued Taxes	119.0	94.5
Accrued Interest	62.9	40.5
Other Current Liabilities	111.3	109.0
TOTAL CURRENT LIABILITIES	1,181.9	1,124.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,719.8	3,730.9
Long-term Risk Management Liabilities	0.4	0.2
Deferred Income Taxes	1,586.0	1,565.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,444.3	1,454.9
Asset Retirement Obligations	98.4	100.2
Employee Benefits and Pension Obligations	68.6	73.3
Deferred Credits and Other Noncurrent Liabilities	88.2	74.7
TOTAL NONCURRENT LIABILITIES	7,005.7	6,999.9
TOTAL LIABILITIES	8,187.6	8,124.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	1,799.7	1,714.1
Accumulated Other Comprehensive Income (Loss)	0.6	1.3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,889.4	3,804.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$12,077.0	$ 11,928.6

See
Condensed
Notes to

Condensed Financial Statements of Registrants beginning on page 120.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$125.5	$110.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	108.5	100.6
Deferred Income Taxes	11.0	52.2
Allowance for Equity Funds Used During Construction	(2.6)	(1.5)
Mark-to-Market of Risk Management Contracts	14.9	6.8
Deferred Fuel Over/Under-Recovery, Net	(90.7)	1.1
Change in Other Noncurrent Assets	3.9	1.0
Change in Other Noncurrent Liabilities	37.9	(3.7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(14.2)	(2.2)
Fuel, Materials and Supplies	19.3	(6.9)
Accounts Payable	(21.6)	(12.7)
Accrued Taxes, Net	17.8	9.4
Other Current Assets	(15.8)	7.8
Other Current Liabilities	5.6	(3.5)
Net Cash Flows from Operating Activities	199.5	259.0
INVESTING ACTIVITIES		
Construction Expenditures	(218.5)	(223.7)
Change in Advances to Affiliates, Net	—	0.4
Other Investing Activities	4.4	1.4
Net Cash Flows Used for Investing Activities	(214.1)	(221.9)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	59.9	102.8
Retirement of Long-term Debt – Nonaffiliated	(11.7)	(115.9)
Principal Payments for Capital Lease Obligations	(1.7)	(1.8)
Dividends Paid on Common Stock	(40.0)	(30.0)
Other Financing Activities	0.2	0.3
Net Cash Flows from (Used for) Financing Activities	6.7	(44.6)
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(7.9)	(7.5)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	19.2	18.5
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$11.3	$11.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$23.4	$23.8
Noncash Acquisitions Under Capital Leases	1.8	0.5
Construction Expenditures Included in Current Liabilities as of March 31,	94.5	63.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days
Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2018	2017
	(in millions of KWhs)	
Retail:		
Residential	1,623	1,492
Commercial	1,176	1,157
Industrial	1,904	1,896
Miscellaneous	20	20
Total Retail	4,723	4,565
Wholesale	2,926	2,954
Total KWhs	7,649	7,519

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Actual – Heating (a)	2,157	1,648
Normal – Heating (b)	2,168	2,185
Actual – Cooling (c)	—	—
Normal – Cooling (b)	2	2

(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.

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

First Quarter of 2017	$68.4
Changes in Gross Margin:	
Retail Margins	3.2
Off-system Sales	0.4
Transmission Revenues	2.8
Other Revenues	(2.7)
Total Change in Gross Margin	3.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(12.1)
Depreciation and Amortization	(9.3)
Taxes Other Than Income Taxes	(2.1)
Interest Income	(0.9)
Carrying Cost Income	(1.0)
Allowance for Equity Funds Used During Construction	(0.3)
Non-Service Cost Components of Net Periodic Benefit Cost	3.0
Interest Expense	(2.0)
Total Change in Expenses and Other	(24.7)
Income Tax Expense	16.8
First Quarter of 2018	$64.2

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 $3 million primarily due to the following:
- A $25 million increase from rate proceedings in the I&M service territory. The increase in Retail Margins relating to riders has corresponding increases in other items below.
- A $14 million increase in weather-related usage primarily due to a 31% increase in heating degree days.

These increases were partially offset by:

- A $16 million decrease related to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
- An $8 million decrease related to over/under recovery of riders.
- A $4 million decrease due to lower weather-normalized margins primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
- A $4 million decrease in FERC generation wholesale municipal and cooperative revenues primarily due to changes to the annual formula rate.
- A $3 million decrease due to increased fuel and other variable production costs not recovered through fuel clauses or other trackers.

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

- Other Operation and Maintenance expenses increased $12 million primarily due to the following:
  - A $12 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase was partially offset within Retail Margins above.
  - A $4 million increase in Cook Plant refueling outage amortization expense, primarily due to increased costs of outages.

  These increases were partially offset by:
  - A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2018.

- Depreciation and Amortization expenses increased $9 million primarily due to a higher depreciable base.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $3 million primarily due to favorable asset returns for the funded Pension and OPEB plans and by moving to a Medicare Advantage arrangement for post-65 retirees in the Non-UMWA OPEB plan. Additionally, the decrease was partially due to the implementation of ASU 2017-07 in 2018, which eliminated I&M’s ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $17 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.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Electric Generation, Transmission and Distribution	$553.9	$538.5
Sales to AEP Affiliates	4.7	0.6
Other Revenues – Affiliated	13.2	18.1
Other Revenues – Nonaffiliated	5.0	3.3
TOTAL REVENUES	576.8	560.5
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	77.5	90.7
Purchased Electricity for Resale	55.6	37.3
Purchased Electricity from AEP Affiliates	61.4	53.9
Other Operation	146.1	137.1
Maintenance	54.5	51.4
Depreciation and Amortization	59.3	50.0
Taxes Other Than Income Taxes	25.0	22.9
TOTAL EXPENSES	479.4	443.3
OPERATING INCOME	97.4	117.2
Other Income (Expense):		
Interest Income	0.2	1.1
Carrying Costs Income	2.4	3.4
Allowance for Equity Funds Used During Construction	1.8	2.1
Non-Service Cost Components of Net Periodic Benefit Cost	4.5	1.5
Interest Expense	(29.7)	(27.7)
INCOME BEFORE INCOME TAX EXPENSE	76.6	97.6
Income Tax Expense	12.4	29.2
NET INCOME	$64.2	$68.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income	$64.2	$68.4
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.1 and $0.2 in 2018 and 2017, Respectively	0.4	0.3
TOTAL COMPREHENSIVE INCOME	$64.6	$68.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 56.6	$ 980.9	$ 1,130.5	$ (16.2)	$ 2,151.8
Common Stock Dividends			(31.3)		(31.3)
Net Income			68.4		68.4
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2017	$ 56.6	$ 980.9	$ 1,167.6	$ (15.9)	$ 2,189.2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 56.6	$ 980.9	$ 1,192.2	$ (12.1)	$ 2,217.6
Common Stock Dividends			(33.5)		(33.5)
ASU 2018-02 Adoption			0.3	(2.7)	(2.4)
Net Income			64.2		64.2
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	$ 56.6	$ 980.9	$ 1,223.2	$ (14.4)	$ 2,246.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$0.6	$ 1.3
Advances to Affiliates	12.5	12.4
Accounts Receivable:		
Customers	48.7	56.4
Affiliated Companies	49.9	50.0
Accrued Unbilled Revenues	8.1	7.3
Miscellaneous	5.4	2.0
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	112.1	115.6
Fuel	35.2	31.4
Materials and Supplies	161.6	160.6
Risk Management Assets	3.3	7.6
Accrued Tax Benefits	65.0	58.4
Regulatory Asset for Under-Recovered Fuel Costs	12.4	15.0
Accrued Reimbursement of Spent Nuclear Fuel Costs	6.2	10.8
Margin Deposits	25.6	11.5
Prepayments and Other Current Assets	13.6	9.4
TOTAL CURRENT ASSETS	448.1	434.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,464.5	4,445.9
Transmission	1,523.5	1,504.0
Distribution	2,097.3	2,069.3
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	610.9	595.2
Construction Work in Progress	503.5	460.2
Total Property, Plant and Equipment	9,199.7	9,074.6
Accumulated Depreciation, Depletion and Amortization	3,073.1	3,024.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,126.6	6,050.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	589.2	579.4
Spent Nuclear Fuel and Decommissioning Trusts	2,510.6	2,527.6
Long-term Risk Management Assets	2.0	0.7
Deferred Charges and Other Noncurrent Assets	168.4	179.9
TOTAL OTHER NONCURRENT ASSETS	3,270.2	3,287.6
TOTAL ASSETS	$9,844.9	$ 9,772.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$314.1	$ 211.6
Accounts Payable:		
General	164.8	154.5
Affiliated Companies	81.4	98.3
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2018 and December 31, 2017 Amounts Include $88.1 and $96.3, Respectively, Related to DCC Fuel)	941.5	474.7
Risk Management Liabilities	3.8	3.5
Customer Deposits	38.0	37.7
Accrued Taxes	89.6	81.3
Accrued Interest	14.8	37.5
Obligations Under Capital Leases	5.8	5.8
Other Current Liabilities	102.7	106.4
TOTAL CURRENT LIABILITIES	1,756.5	1,211.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,775.7	2,270.4
Long-term Risk Management Liabilities	0.2	0.1
Deferred Income Taxes	978.3	953.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,660.2	1,708.7
Asset Retirement Obligations	1,336.0	1,321.6
Deferred Credits and Other Noncurrent Liabilities	91.7	88.5
TOTAL NONCURRENT LIABILITIES	5,842.1	6,343.1
TOTAL LIABILITIES	7,598.6	7,554.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,223.2	1,192.2
Accumulated Other Comprehensive Income (Loss)	(14.4)	(12.1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,246.3	2,217.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,844.9	$ 9,772.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,					
	2018			2017		
OPERATING ACTIVITIES						
Net Income	$	64.2		$	68.4	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:						
Depreciation and Amortization	59.3			50.0		
Deferred Income Taxes	13.7			48.8		
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(12.3		)	16.6		
Allowance for Equity Funds Used During Construction	(1.8		)	(2.1		)
Mark-to-Market of Risk Management Contracts	3.4			2.3		
Amortization of Nuclear Fuel	27.4			35.1		
Deferred Fuel Over/Under-Recovery, Net	3.4			19.6		
Change in Other Noncurrent Assets	(13.4		)	(17.6		)
Change in Other Noncurrent Liabilities	33.7			13.5		
Changes in Certain Components of Working Capital:						
Accounts Receivable, Net	3.5			3.0		
Fuel, Materials and Supplies	(4.5		)	(8.5		)
Accounts Payable	1.3			(22.5		)
Accrued Taxes, Net	8.2			(6.9		)
Other Current Assets	(11.1		)	15.8		
Other Current Liabilities	(27.8		)	(41.2		)
Net Cash Flows from Operating Activities	147.2			174.3		
INVESTING ACTIVITIES						
Construction Expenditures	(148.9		)	(159.7		)
Change in Advances to Affiliates, Net	(0.1		)	—		
Purchases of Investment Securities	(525.3		)	(505.5		)
Sales of Investment Securities	508.6			487.9		

Acquisitions of Nuclear Fuel	(23.8)	(3.7)
Other Investing Activities	4.2	2.0
Net Cash Flows Used for Investing Activities	(185.3)	(179.0)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	76.7
Change in Advances from Affiliates, Net	102.5	71.6
Retirement of Long-term Debt – Nonaffiliated	(29.4)	(109.5)
Principal Payments for Capital Lease Obligations	(2.7)	(2.9)
Dividends Paid on Common Stock	(33.5)	(31.3)
Other Financing Activities	0.5	0.1
Net Cash Flows from Financing Activities	37.4	4.7
Net Decrease in Cash and Cash Equivalents	(0.7)	—
Cash and Cash Equivalents at Beginning of Period	1.3	1.2
Cash and Cash Equivalents at End of Period	$ 0.6	$ 1.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 50.6	$ 44.3
Net Cash Paid for Income Taxes	—	0.6
Noncash Acquisitions Under Capital Leases	1.7	1.5
Construction Expenditures Included in Current Liabilities as of March 31,	77.2	75.9
Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31,	0.1	—
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.1	1.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2018	2017
	(in millions of KWhs)	
Retail:		
Residential	4,133	3,693
Commercial	3,552	3,428
Industrial	3,554	3,569
Miscellaneous	31	32
Total Retail (a)	11,270	10,722
Wholesale (b)	667	674
Total KWhs	11,937	11,396

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

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Actual – Heating (a)	1,884	1,403
Normal – Heating (b)	1,884	1,899
Actual – Cooling (c)	4	3
Normal – Cooling (b)	3	3

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

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

First Quarter of 2017	$ 86.2
Changes in Gross Margin:	
Retail Margins	31.8
Off-system Sales	7.2
Transmission Revenues	(6.4)
Other Revenues	(0.9)
Total Change in Gross Margin	31.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(49.9)
Depreciation and Amortization	(7.5)
Taxes Other Than Income Taxes	(6.6)
Interest Income	(1.6)
Carrying Costs Income	(1.2)
Allowance for Equity Funds Used During Construction	0.1
Non-Service Cost Components of Net Periodic Benefit Cost	2.8
Interest Expense	(0.2)
Total Change in Expenses and Other	(64.1)
Income Tax Expense	25.8
First Quarter of 2018	$ 79.6

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 $32 million primarily due to the following:
  - A $39 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by a corresponding increase in Other Operation and Maintenance below.
  - A $21 million increase in revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - A $9 million increase in usage primarily in the residential class.
  - A $6 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $4 million net increase in RSR revenues less associated amortizations.

  These increases were partially offset by:
  - A $16 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
  - An $11 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues. This decrease was partially offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - A $10 million decrease in margin for the Phase-In-Recovery Rider including associated amortizations.
  - A $7 million decrease due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.

- A $7 million decrease in revenues associated with smart grid riders. This decrease was partially offset by a corresponding decrease in various expenses below.

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- Margins from Off-system Sales increased $7 million primarily due to lower current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
- Transmission Revenues decreased $6 million mainly due to the 2018 provisions for customer refunds primarily due to Tax Reform. This decrease is offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $50 million primarily due to the following:
  - A $35 million increase in recoverable PJM expenses. This increase was offset by a corresponding increase in Retail 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.

  These increases were partially offset by:
  - A $10 million decrease in Energy Efficiency/Peak Demand Reduction rider costs and associated deferrals. This decrease was offset by a decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $8 million primarily due to the following:
  - A $6 million increase in recoverable DIR depreciation expense. This increase was offset in Retail Margins above.
  - A $3 million increase in depreciation expense due to an increase in depreciable base of transmission and distribution assets.
  - A $2 million increase primarily due to amortization of capitalized software costs.

  These increases were partially offset by:
  - A $3 million decrease in recoverable smart grid depreciation expenses. This decrease was offset in Retail Margins above.
- Taxes Other Than Income Taxes increased by $7 million primarily due to the following:
  - A $4 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
  - A $3 million increase in state excise taxes due to an increase in metered KWh. This increase was offset by a corresponding increase in Retail Margins above.
- Income Tax Expense decreased $26 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.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Electricity, Transmission and Distribution	$786.3	$738.4
Sales to AEP Affiliates	3.1	5.7
Other Revenues	1.5	2.0
TOTAL REVENUES	790.9	746.1
EXPENSES		
Purchased Electricity for Resale	205.5	188.3
Purchased Electricity from AEP Affiliates	30.2	32.0
Amortization of Generation Deferrals	58.6	60.9
Other Operation	172.2	122.3
Maintenance	37.2	37.2
Depreciation and Amortization	64.8	57.3
Taxes Other Than Income Taxes	105.1	98.5
TOTAL EXPENSES	673.6	596.5
OPERATING INCOME	117.3	149.6
Other Income (Expense):		
Interest Income	0.9	2.5
Carrying Costs Income	0.7	1.9
Allowance for Equity Funds Used During Construction	2.5	2.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.9	1.1
Interest Expense	(25.2)	(25.0)
INCOME BEFORE INCOME TAX EXPENSE	100.1	132.5
Income Tax Expense	20.5	46.3
NET INCOME	$79.6	$86.2

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income	$79.6	$86.2
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) in 2018 and 2017, Respectively	(0.3)	(0.2)
TOTAL COMPREHENSIVE INCOME	$79.3	$86.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 321.2	$ 838.8	$ 954.5	$ 3.0	$ 2,117.5
Common Stock Dividends			(65.0)		(65.0)
Net Income			86.2		86.2
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2017	$ 321.2	$ 838.8	$ 975.7	$ 2.8	$ 2,138.5
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 321.2	$ 838.8	$ 1,148.4	$ 1.9	$ 2,310.3
Common Stock Dividends			(112.5)		(112.5)
ASU 2018-02 Adoption				0.4	0.4
Net Income			79.6		79.6
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	$ 321.2	$ 838.8	$ 1,115.5	$ 2.0	$ 2,277.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$1.4	$ 3.1
Restricted Cash for Securitized Funding	15.9	26.6
Advances to Affiliates	200.4	—
Accounts Receivable:		
Customers	42.0	67.8
Affiliated Companies	60.4	70.2
Accrued Unbilled Revenues	27.2	29.7
Miscellaneous	1.2	1.9
Allowance for Uncollectible Accounts	(0.6)	(0.6)
Total Accounts Receivable	130.2	169.0
Materials and Supplies	41.2	41.9
Renewable Energy Credits	24.8	25.0
Risk Management Assets	0.4	0.6
Regulatory Asset for Under-Recovered Fuel Costs	89.3	115.9
Prepayments and Other Current Assets	27.1	15.8
TOTAL CURRENT ASSETS	530.7	397.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,440.5	2,419.2
Distribution	4,669.3	4,626.4
Other Property, Plant and Equipment	518.9	495.9
Construction Work in Progress	432.0	410.1
Total Property, Plant and Equipment	8,060.7	7,951.6
Accumulated Depreciation and Amortization	2,205.7	2,184.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,855.0	5,766.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	597.6	652.8
Securitized Assets	31.4	37.7
Deferred Charges and Other Noncurrent Assets	342.0	406.5
TOTAL OTHER NONCURRENT ASSETS	971.0	1,097.0
TOTAL ASSETS	$7,356.7	$ 7,261.7

See Condensed Notes to Condensed Financial

Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$—	$ 87.8
Accounts Payable:		
General	159.9	205.8
Affiliated Companies	105.5	118.2
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2018 and December 31, 2017 Amounts Include $47.5 and $47, Respectively, Related to Ohio Phase-in-Recovery Funding)	397.5	397.0
Risk Management Liabilities	5.3	6.4
Customer Deposits	76.5	69.2
Accrued Taxes	418.5	512.5
Accrued Interest	38.7	31.0
Other Current Liabilities	161.2	165.9
TOTAL CURRENT LIABILITIES	1,363.1	1,593.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (March 31, 2018 and December 31, 2017 Amounts Include $24.3 and $47.5, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,692.2	1,322.3
Long-term Risk Management Liabilities	93.2	126.0
Deferred Income Taxes	759.0	762.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,120.8	1,100.2
Deferred Credits and Other Noncurrent Liabilities	50.9	46.2
TOTAL NONCURRENT LIABILITIES	3,716.1	3,357.6
TOTAL LIABILITIES	5,079.2	4,951.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,115.5	1,148.4
Accumulated Other Comprehensive Income (Loss)	2.0	1.9
TOTAL COMMON SHAREHOLDER'S EQUITY	2,277.5	2,310.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$7,356.7	$ 7,261.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$79.6	$86.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	64.8	57.3
Amortization of Generation Deferrals	58.6	60.9
Deferred Income Taxes	(4.9)	36.7
Carrying Costs Income	(0.7)	(1.9)
Allowance for Equity Funds Used During Construction	(2.5)	(2.4)
Mark-to-Market of Risk Management Contracts	(33.7)	5.7
Property Taxes	62.9	58.4
Provision for Refund – Global Settlement	(5.4)	—
Change in Other Noncurrent Assets	14.3	(45.8)
Change in Other Noncurrent Liabilities	40.6	30.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	38.8	30.2
Materials and Supplies	(1.9)	(1.8)
Accounts Payable	(22.5)	(34.9)
Accrued Taxes, Net	(92.8)	(107.2)
Other Current Assets	(7.5)	(0.3)
Other Current Liabilities	(2.9)	(31.2)
Net Cash Flows from Operating Activities	184.8	140.5
INVESTING ACTIVITIES		
Construction Expenditures	(168.2)	(108.4)
Change in Advances to Affiliates, Net	(200.4)	24.2
Other Investing Activities	1.7	2.0
Net Cash Flows Used for Investing Activities	(366.9)	(82.2)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	393.3	—
Change in Advances from Affiliates, Net	(87.8)	18.3
Retirement of Long-term Debt – Nonaffiliated	(22.9)	(22.5)
Principal Payments for Capital Lease Obligations	(0.9)	(1.0)
Dividends Paid on Common Stock	(112.5)	(65.0)
Other Financing Activities	0.5	0.6
Net Cash Flows from (Used for) Financing Activities	169.7	(69.6)
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(12.4)	(11.3)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	29.7	30.3
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$17.3	$19.0

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$17.0	$17.2
Net Cash Paid for Income Taxes	—	1.7
Noncash Acquisitions Under Capital Leases	1.4	1.3
Construction Expenditures Included in Current Liabilities as of March 31,	52.3	28.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2018	2017
	(in millions of KWhs)	
Retail:		
Residential	1,493	1,312
Commercial	1,162	1,130
Industrial	1,340	1,306
Miscellaneous	276	273
Total Retail	4,271	4,021
Wholesale	157	81
Total KWhs	4,428	4,102

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Actual – Heating (a)	1,032	670
Normal – Heating (b)	1,041	1,062
Actual – Cooling (c)	12	59
Normal – Cooling (b)	17	14

(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.

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

First Quarter of 2017	$4.8
Changes in Gross Margin:	
Retail Margins (a)	(0.2)
Off-system Sales	0.1
Other Revenues	(0.4)
Total Change in Gross Margin	(0.5)
Changes in Expenses and Other:	
Other Operation and Maintenance	(11.2)
Depreciation and Amortization	(3.3)
Taxes Other Than Income Taxes	(1.0)
Non-Service Cost Components of Net Periodic Benefit Cost	1.3
Other Income	(0.5)
Interest Expense	(1.1)
Total Change in Expenses and Other	(15.8)
Income Tax Expense	4.3
First Quarter of 2018	$(7.2)

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

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

- Retail Margins were consistent with the prior year due to the following:
  - A $5 million increase in revenue from rate riders. This increase in Retail Margins is partially offset by a corresponding increase to riders/trackers recognized in other expense items below.
  - A $4 million increase due to new rates implemented in March 2018, inclusive of a $2 million decrease due to the change in the corporate federal tax rate.
  - A $3 million increase in weather-related usage due to a 54% increase in heating degree days.

  These increases were partially offset by:
  - A $6 million decrease due to 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
  - A $5 million decrease related to the System Reliability Rider (SRR) that ended in August 2017. This decrease is partially offset by a corresponding decrease recognized in other expense items below.
  - A $1 million decrease due to lower weather-normalized margins.

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

- Other Operation and Maintenance expenses increased $11 million primarily due to the following:
  - A $9 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $4 million increase due to the Wind Catcher Project.

- A $3 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.

These increases were partially offset by:

- A $6 million decrease in the amortization of previously deferred vegetation management costs collected through the SRR. This decrease was partially offset by a corresponding decrease in Retail Margins above.
- Depreciation and Amortization expenses increased $3 million primarily due to the following:
- A $2 million increase due to a higher depreciable base.
- A $1 million increase due to amortization of capitalized software costs.
- Income Tax Expense decreased $4 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 accumulated deferred income taxes associated with certain depreciable property and a decrease in pretax book income.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Electric Generation, Transmission and Distribution	$335.1	$301.9
Sales to AEP Affiliates	1.1	1.1
Other Revenues	0.6	1.1
TOTAL REVENUES	336.8	304.1
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	48.4	12.3
Purchased Electricity for Resale	122.4	125.3
Other Operation	86.8	68.3
Maintenance	26.9	34.2
Depreciation and Amortization	36.8	33.5
Taxes Other Than Income Taxes	11.6	10.6
TOTAL EXPENSES	332.9	284.2
OPERATING INCOME	3.9	19.9
Other Income (Expense):		
Other Income	—	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.2	0.9
Interest Expense	(14.7)	(13.6)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)	(8.6)	7.7
Income Tax Expense (Credit)	(1.4)	2.9
NET INCOME (LOSS)	$(7.2)	$4.8

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

See Condensed Notes to Condensed Financial Statements of

Registrants beginning on page 120.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income (Loss)	$(7.2)	$4.8
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) in 2018 and 2017, Respectively	(0.2)	(0.2)
TOTAL COMPREHENSIVE INCOME (LOSS)	$(7.4)	$4.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 157.2	$ 364.0	$ 689.5	$ 3.4	$ 1,214.1
Common Stock Dividends			(17.5)		(17.5)
Net Income			4.8		4.8
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2017	$ 157.2	$ 364.0	$ 676.8	$ 3.2	$ 1,201.2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 157.2	$ 364.0	$ 691.5	$ 2.6	$ 1,215.3
Common Stock Dividends			(12.5)		(12.5)
ASU 2018-02 Adoption				0.5	0.5
Net Loss			(7.2)		(7.2)
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	$ 157.2	$ 364.0	$ 671.8	$ 2.9	$ 1,195.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$0.6	$ 1.6
Accounts Receivable:		
Customers	30.9	32.5
Affiliated Companies	27.7	32.9
Miscellaneous	3.9	4.1
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	62.5	69.4
Fuel	13.0	12.5
Materials and Supplies	43.2	42.0
Risk Management Assets	2.9	6.4
Accrued Tax Benefits	30.2	28.1
Regulatory Asset for Under-Recovered Fuel Costs	22.7	36.7
Prepayments and Other Current Assets	7.5	8.6
TOTAL CURRENT ASSETS	182.6	205.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,572.4	1,577.2
Transmission	862.0	858.8
Distribution	2,475.5	2,445.1
Other Property, Plant and Equipment	297.0	287.4
Construction Work in Progress	110.3	111.3
Total Property, Plant and Equipment	5,317.2	5,279.8
Accumulated Depreciation and Amortization	1,415.5	1,393.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,901.7	3,886.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	366.8	368.1
Employee Benefits and Pension Assets	40.4	40.0
Deferred Charges and Other Noncurrent Assets	34.2	8.7
TOTAL OTHER NONCURRENT ASSETS	441.4	416.8
TOTAL ASSETS	$4,525.7	$ 4,508.3

See Condensed Notes to Condensed Financial Statements

of
Registrants
beginning
on page
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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2018 and December 31, 2017
(Unaudited)

	March 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$179.1	$ 149.6
Accounts Payable:		
General	88.7	102.4
Affiliated Companies	51.5	48.0
Long-term Debt Due Within One Year – Nonaffiliated	0.5	0.5
Customer Deposits	54.5	54.1
Accrued Taxes	42.1	22.6
Accrued Interest	19.3	14.1
Other Current Liabilities	34.8	44.7
TOTAL CURRENT LIABILITIES	470.5	436.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,286.2	1,286.0
Deferred Income Taxes	639.6	642.0
Regulatory Liabilities and Deferred Investment Tax Credits	851.5	853.5
Asset Retirement Obligations	53.7	53.0
Deferred Credits and Other Noncurrent Liabilities	28.3	22.5
TOTAL NONCURRENT LIABILITIES	2,859.3	2,857.0
TOTAL LIABILITIES	3,329.8	3,293.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	671.8	691.5
Accumulated Other Comprehensive Income (Loss)	2.9	2.6
TOTAL COMMON SHAREHOLDER'S EQUITY	1,195.9	1,215.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,525.7	$ 4,508.3

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Financial Statements of Registrants beginning on page 120.

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PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
OPERATING ACTIVITIES		
Net Income (Loss)	$(7.2)	$4.8
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	36.8	33.5
Deferred Income Taxes	(4.5)	27.4
Allowance for Equity Funds Used During Construction	0.1	(0.4)
Mark-to-Market of Risk Management Contracts	3.5	0.3
Property Taxes	(30.1)	(29.8)
Deferred Fuel Over/Under-Recovery, Net	14.6	(13.1)
Change in Other Noncurrent Assets	—	(9.3)
Change in Other Noncurrent Liabilities	5.7	(1.9)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	6.9	16.6
Fuel, Materials and Supplies	(1.7)	3.4
Accounts Payable	(10.9)	(27.7)
Accrued Taxes, Net	22.4	(0.3)
Other Current Assets	0.9	0.3
Other Current Liabilities	(1.3)	(22.3)
Net Cash Flows from (Used for) Operating Activities	35.2	(18.5)
INVESTING ACTIVITIES		
Construction Expenditures	(54.4)	(75.7)
Other Investing Activities	2.0	0.9
Net Cash Flows Used for Investing Activities	(52.4)	(74.8)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	29.5	111.7
Retirement of Long-term Debt – Nonaffiliated	(0.1)	(0.1)
Principal Payments for Capital Lease Obligations	(1.0)	(1.1)
Dividends Paid on Common Stock	(12.5)	(17.5)
Other Financing Activities	0.3	0.1
Net Cash Flows from Financing Activities	16.2	93.1
Net Decrease in Cash and Cash Equivalents	(1.0)	(0.2)
Cash and Cash Equivalents at Beginning of Period	1.6	1.5
Cash and Cash Equivalents at End of Period	$0.6	$1.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$10.3	$15.9
Net Cash Paid (Received) for Income Taxes	—	(2.6)

Noncash Acquisitions Under Capital Leases	0.9	0.7
Construction Expenditures Included in Current Liabilities as of March 31,	25.4	22.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2018	2017
	(in millions of KWhs)	
Retail:		
Residential	1,558	1,310
Commercial	1,288	1,305
Industrial	1,199	1,222
Miscellaneous	19	20
Total Retail	4,064	3,857
Wholesale	1,908	2,439
Total KWhs	5,972	6,296

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2018	2017
	(in degree days)	
Actual – Heating (a)	729	388
Normal – Heating (b)	707	720
Actual – Cooling (c)	60	106
Normal – Cooling (b)	38	34

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

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

First Quarter of 2017	$16.3
Changes in Gross Margin:	
Retail Margins (a)	10.2
Off-system Sales	(1.1)
Transmission Revenues	2.7
Other Revenues	0.1
Total Change in Gross Margin	11.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(14.8)
Depreciation and Amortization	(6.6)
Taxes Other Than Income Taxes	(1.7)
Interest Income	0.9
Allowance for Equity Funds Used During Construction	1.5
Non-Service Cost Components of Net Periodic Benefit Cost	1.4
Interest Expense	(2.3)
Total Change in Expenses and Other	(21.6)
Income Tax Expense	6.6
Equity Earnings of Unconsolidated Subsidiary	(0.8)
Net Income Attributable to Noncontrolling Interest	(0.6)
First Quarter of 2018	$11.8

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

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

- Retail Margins increased $10 million primarily due to the following:
  - A $22 million increase primarily due to rider and base rate revenue increases in Texas and Louisiana.
  - A $14 million increase in weather-related usage primarily due to an 88% increase in heating degree days.

  These increases were partially offset by:
  - A $15 million decrease due to lower weather-normalized margins, primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
  - A $12 million decrease due to the 2018 provisions for customer refunds primarily related to Tax Reform. This decrease is offset in Income Tax Expense below.
- Transmission Revenues increased $3 million primarily due to an increase in transmission investments in SPP.

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

- Other Operation and Maintenance expenses increased $15 million primarily due to the following:
  - A $10 million increase due to the Wind Catcher Project.

- A $5 million increase in SPP transmission services.
- A $3 million increase in employee-related expenses.

These increases were partially offset by:

- A $4 million decrease in distribution expenses primarily due to distribution system improvements in 2017.
- Depreciation and Amortization expenses increased $7 million primarily due to a higher depreciable base.

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- Income Tax Expense decreased $7 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 accumulated deferred income taxes associated with certain depreciable property and a decrease in pretax book income.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Electric Generation, Transmission and Distribution	$413.0	$396.3
Sales to AEP Affiliates	6.1	4.6
Other Revenues	0.3	0.4
TOTAL REVENUES	419.4	401.3
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	126.8	130.9
Purchased Electricity for Resale	42.7	32.4
Other Operation	94.9	78.9
Maintenance	31.0	32.2
Depreciation and Amortization	57.4	50.8
Taxes Other Than Income Taxes	25.0	23.3
TOTAL EXPENSES	377.8	348.5
OPERATING INCOME	41.6	52.8
Other Income (Expense):		
Interest Income	1.8	0.9
Allowance for Equity Funds Used During Construction	2.3	0.8
Non-Service Cost Components of Net Periodic Benefit Cost	2.3	0.9
Interest Expense	(32.2)	(29.9)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	15.8	25.5
Income Tax Expense	2.9	9.5
Equity Earnings of Unconsolidated Subsidiary	0.5	1.3
NET INCOME	13.4	17.3
Net Income Attributable to Noncontrolling Interest	1.6	1.0
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$11.8	$16.3

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net Income	$13.4	$17.3
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.1 and $0.2 in 2018 and 2017, Respectively	0.4	0.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) in 2018 and 2017, Respectively	(0.3)	(0.2)
TOTAL OTHER COMPREHENSIVE INCOME	0.1	0.3
TOTAL COMPREHENSIVE INCOME	13.5	17.6
Total Comprehensive Income Attributable to Noncontrolling Interest	1.6	1.0
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$11.9	$16.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2016	$135.7	$676.6	$1,411.9	$ (9.4)	$ 0.4	$2,215.2
Common Stock Dividends			(27.5)			(27.5)
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			16.3		1.0	17.3
Other Comprehensive Income				0.3		0.3
TOTAL EQUITY – MARCH 31, 2017	$135.7	$676.6	$1,400.7	$ (9.1)	$ 0.3	$2,204.2
TOTAL EQUITY – DECEMBER 31, 2017	$135.7	$676.6	$1,426.6	$ (4.0)	$ (0.4)	$2,234.5
Common Stock Dividends			(20.0)			(20.0)
Common Stock Dividends – Nonaffiliated					(0.8)	(0.8)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			11.8		1.6	13.4
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – MARCH 31, 2018	$135.7	$676.6	$1,418.0	$ (4.8)	$ 0.4	$2,225.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$0.7	$ 1.6
Advances to Affiliates	2.0	2.0
Accounts Receivable:		
Customers	67.0	70.9
Affiliated Companies	18.0	30.2
Miscellaneous	13.2	25.8
Allowance for Uncollectible Accounts	(0.5)	(1.3)
Total Accounts Receivable	97.7	125.6
Fuel (March 31, 2018 and December 31, 2017 Amounts Include $37.7 and $41.5, Respectively, Related to Sabine)	120.5	123.6
Materials and Supplies	68.8	67.9
Risk Management Assets	1.7	6.4
Regulatory Asset for Under-Recovered Fuel Costs	16.5	14.1
Prepayments and Other Current Assets	40.2	39.2
TOTAL CURRENT ASSETS	348.1	380.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,622.6	4,624.9
Transmission	1,715.0	1,679.8
Distribution	2,108.1	2,095.8
Other Property, Plant and Equipment (March 31, 2018 and December 31, 2017 Amounts Include $264.9 and $266.7, Respectively, Related to Sabine)	704.4	684.1
Construction Work in Progress	266.9	233.2
Total Property, Plant and Equipment	9,417.0	9,317.8
Accumulated Depreciation and Amortization (March 31, 2018 and December 31, 2017 Amounts Include $167.4 and $165.9, Respectively, Related to Sabine)	2,724.7	2,685.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,692.3	6,632.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	217.9	220.6
Deferred Charges and Other Noncurrent Assets	165.5	109.9
TOTAL OTHER NONCURRENT ASSETS	383.4	330.5
TOTAL ASSETS	$7,423.8	$ 7,342.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

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

	March 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$148.6	$ 118.7
Accounts Payable:		
General	118.5	160.4
Affiliated Companies	60.7	63.7
Short-term Debt – Nonaffiliated	22.6	22.0
Long-term Debt Due Within One Year – Nonaffiliated	457.2	3.7
Risk Management Liabilities	0.1	0.2
Customer Deposits	62.9	62.1
Accrued Taxes	91.1	39.0
Accrued Interest	25.9	38.9
Obligations Under Capital Leases	11.3	11.2
Other Current Liabilities	60.4	78.7
TOTAL CURRENT LIABILITIES	1,059.3	598.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,046.5	2,438.2
Long-term Risk Management Liabilities	0.5	—
Deferred Income Taxes	924.2	917.7
Regulatory Liabilities and Deferred Investment Tax Credits	895.2	896.4
Asset Retirement Obligations	160.8	160.3
Employee Benefits and Pension Obligations	18.1	19.5
Obligations Under Capital Leases	56.9	57.8
Deferred Credits and Other Noncurrent Liabilities	36.4	19.9
TOTAL NONCURRENT LIABILITIES	4,138.6	4,509.8
TOTAL LIABILITIES	5,197.9	5,108.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135.7	135.7
Paid-in Capital	676.6	676.6
Retained Earnings	1,418.0	1,426.6
Accumulated Other Comprehensive Income (Loss)	(4.8)	(4.0)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,225.5	2,234.9

Noncontrolling Interest	0.4	(0.4)
TOTAL EQUITY	2,225.9	2,234.5
TOTAL LIABILITIES AND EQUITY	$7,423.8	$ 7,342.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended March 31, 2018		2017	
OPERATING ACTIVITIES				
Net Income	$ 13.4		$ 17.3	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	57.4		50.8	
Deferred Income Taxes	1.0		43.1	
Allowance for Equity Funds Used During Construction	(2.3	)	(0.8	)
Mark-to-Market of Risk Management Contracts	5.1		0.4	
Property Taxes	(48.8	)	(45.3	)
Deferred Fuel Over/Under-Recovery, Net	(4.6	)	(3.4	)
Change in Other Noncurrent Assets	1.3		(0.6	)
Change in Other Noncurrent Liabilities	18.8		(12.1	)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	27.9		23.1	
Fuel, Materials and Supplies	2.2		12.5	
Accounts Payable	(24.6	)	(33.5	)
Accrued Taxes, Net	55.2		11.8	
Accrued Interest	(13.0	)	(20.3	)
Other Current Assets	(0.8	)	3.2	
Other Current Liabilities	(12.5	)	(19.1	)
Net Cash Flows from Operating Activities	75.7		27.1	
INVESTING ACTIVITIES				
Construction Expenditures	(139.7	)	(75.6	)
Change in Advances to Affiliates, Net	—		167.8	
Other Investing Activities	(5.4	)	(4.4	)
Net Cash Flows from (Used for) Investing Activities	(145.1	)	87.8	
FINANCING ACTIVITIES				
	444.6		—	

Issuance of Long-term Debt – Nonaffiliated		
Change in Short-term Debt, Net – Nonaffiliated	0.6	—
Change in Advances from Affiliates, Net	29.9	167.9
Retirement of Long-term Debt – Nonaffiliated	(383.4)	(251.7)
Principal Payments for Capital Lease Obligations	(2.8)	(2.8)
Dividends Paid on Common Stock	(20.0)	(27.5)
Dividends Paid on Common Stock – Nonaffiliated	(0.8)	(1.1)
Other Financing Activities	0.4	0.3
Net Cash Flows from (Used for) Financing Activities	68.5	(114.9)
Net Decrease in Cash and Cash Equivalents	(0.9)	—
Cash and Cash Equivalents at Beginning of Period	1.6	10.3
Cash and Cash Equivalents at End of Period	$ 0.7	$ 10.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 43.7	$ 50.6
Net Cash Paid (Received) for Income Taxes	(0.1)	—
Noncash Acquisitions Under Capital Leases	1.9	1.3
Construction Expenditures Included in Current Liabilities as of March 31,	50.3	31.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 120.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three months ended March 31, 2018 is not necessarily indicative of results that may be expected for the year ending December 31, 2018. The condensed financial statements are unaudited and should be read in conjunction with the audited 2017 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 22, 2018.

Earnings Per Share (EPS) (Applies to AEP)

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

The following table presents AEP's basic and diluted EPS calculations included on the statements of income:

	Three Months Ended March 31,			
	2018		2017	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$454.4		$592.2	
Weighted Average Number of Basic Shares Outstanding	492.3	$ 0.92	491.7	$ 1.20
Weighted Average Dilutive Effect of Stock-Based Awards	0.8	—	0.3	—
Weighted Average Number of Diluted Shares Outstanding	493.1	$ 0.92	492.0	$ 1.20

There were no antidilutive shares outstanding as of March 31, 2018 and 2017.

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	March 31, 2018			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			

Cash and Cash Equivalents	$183.4	$0.1	$1.2	$1.4
Restricted Cash	133.1	107.1	10.1	15.9
Total Cash, Cash Equivalents and Restricted Cash	$316.5	$107.2	$11.3	$17.3

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

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

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

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

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

In January 2016, the FASB issued ASU 2016-01 revising the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. For equity investments that do not have a readily determinable fair value, entities are permitted to elect a practicality exception and measure the investment at cost, less impairment, plus or minus observable price changes. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheets or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted for certain provisions. Management adopted ASU 2016-01 effective January 1, 2018, by means of a cumulative-effect adjustment to the balance sheet. The adoption of ASU 2016-01 resulted in an immaterial impact on results of operations and financial position of AEP, and no impact to results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

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

The new accounting guidance is effective for annual periods beginning after December 15, 2018, with early adoption permitted. Initial decisions were made to apply the guidance by means of a modified retrospective approach. The modified retrospective approach will require lessees and lessors to recognize and measure leases at the beginning of the earliest period presented; however, the FASB is currently evaluating draft guidance which would provide an optional expedient to adopt the new lease requirements through a cumulative-effect adjustment in the period of adoption. Management continues to monitor these standard-setting activities that may impact the transition requirements of the lease standard.

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

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Lease term	Elect to use hindsight to determine the lease term.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.

Evaluation of new lease contracts continues and the process of implementing a compliant lease system solution began in the third quarter of 2017. Management expects the new standard to impact financial position and, at this time, cannot estimate the impact. Management expects no impact to results of operations or cash flows.

Management continues to monitor industry implementation issues as well as FASB’s ongoing standard-setting activities that may result in the issuance of additional targeted improvements to the new lease guidance. Management plans to adopt ASU 2016-02 effective January 1, 2019.

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 effective January 1, 2020.

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

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented on the statements of income separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component will be eligible for capitalization as applicable following labor.

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

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

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

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

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

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

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

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three months ended March 31, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2017	$(28.4)	$(13.0)	$ 11.9	$(38.3)	$(67.8)
Change in Fair Value Recognized in AOCI	12.8	—	—	—	12.8
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale	(13.1)	—	—	—	(13.1)
Interest Expense	—	0.3	—	—	0.3
Amortization of Prior Service Cost (Credit)	—	—	—	(5.0)	(5.0)
Amortization of Actuarial (Gains)/Losses	—	—	—	3.2	3.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(13.1)	0.3	—	(1.8)	(14.6)
Income Tax (Expense) Credit	(2.8)	0.1	—	(0.4)	(3.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(10.3)	0.2	—	(1.4)	(11.5)
Net Current Period Other Comprehensive Income (Loss)	2.5	0.2	—	(1.4)	1.3
ASU 2018-02 Adoption (a)	(6.1)	(2.7)	—	(8.2)	(17.0)
ASU 2016-01 Adoption (a)	—	—	(11.9)	—	(11.9)
Balance in AOCI as of March 31, 2018	$(32.0)	$(15.5)	$ —	$(47.9)	$(95.4)

(a) See Note 2 - New Accounting Pronouncements for additional information.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2016	$(23.1)	$(15.7)	$ 8.4	$(125.9)	$(156.3)

Change in Fair Value Recognized in AOCI	(21.8)	—	1.2	—	(20.6)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues	(4.7)	—	—	—	(4.7)
Purchased Electricity for Resale	12.8	—	—	—	12.8
Interest Expense	—	0.5	—	—	0.5
Amortization of Prior Service Cost (Credit)	—	—	—	(4.9)	(4.9)
Amortization of Actuarial (Gains)/Losses	—	—	—	5.3	5.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	8.1	0.5	—	0.4	9.0
Income Tax (Expense) Credit	2.8	0.1	—	0.2	3.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	5.3	0.4	—	0.2	5.9
Net Current Period Other Comprehensive Income (Loss)	(16.5)	0.4	1.2	0.2	(14.7)
Balance in AOCI as of March 31, 2017	$(39.6)	$(15.3)	$ 9.6	$(125.7)	$(171.0)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ (8.1)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.3	—	0.3
Amortization of Prior Service Cost (Credit)	—	—	—
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.3	0.1	0.4
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.2	0.1	0.3
Net Current Period Other Comprehensive Income (Loss)	0.2	0.1	0.3
ASU 2018-02 Adoption (a)	(0.9)	(1.8)	(2.7)
Balance in AOCI as of March 31, 2018	$ (5.2)	$ (9.8)	$ (15.0)

(a) See Note 2 - New Accounting Pronouncements for additional information.

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ (9.5)	$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.3	—	0.3
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.3	0.1	0.4
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.2	0.1	0.3
Net Current Period Other Comprehensive Income (Loss)	0.2	0.1	0.3
Balance in AOCI as of March 31, 2017	$ (5.2)	$ (9.4)	$ (14.6)

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APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ (0.9)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(0.7)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale	0.9	—	—	0.9
Interest Expense	—	(0.3)	—	(0.3)
Amortization of Prior Service Cost (Credit)	—	—	(1.3)	(1.3)
Amortization of Actuarial (Gains)/Losses	—	—	0.3	0.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.9	(0.3)	(1.0)	(0.4)
Income Tax (Expense) Credit	0.2	(0.1)	(0.2)	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.7	(0.2)	(0.8)	(0.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.2)	(0.8)	(1.0)
ASU 2018-02 Adoption (a)	—	0.5	(0.2)	0.3
Balance in AOCI as of March 31, 2018	$ —	$ 2.5	$ (1.9)	$ 0.6

(a) See Note 2 - New Accounting Pronouncements for additional information.

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$ 2.9	$ (11.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	(0.3)	—	(0.3)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains)/Losses	—	0.8	0.8
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)	(0.5)	(0.8)
Income Tax (Expense) Credit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)	(0.3)	(0.5)
Net Current Period Other Comprehensive Income (Loss)	(0.2)	(0.3)	(0.5)
Balance in AOCI as of March 31, 2017	$ 2.7	$ (11.6)	$ (8.9)

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I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$(10.7)	$(1.4)	$(12.1)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	—	0.5
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	—	0.4
Net Current Period Other Comprehensive Income (Loss)	0.4	—	0.4
ASU 2018-02 Adoption (a)	(2.4)	(0.3)	(2.7)
Balance in AOCI as of March 31, 2018	$(12.7)	$(1.7)	$(14.4)

(a) See Note 2 - New Accounting Pronouncements for additional information.

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(12.0)	$(4.2)	$(16.2)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	—	0.5
Income Tax (Expense) Credit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3

Balance in AOCI as of March 31, 2017	$(11.7)	$(4.2)	$(15.9)

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OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
ASU 2018-02 Adoption (a)	0.4
Balance in AOCI as of March 31, 2018	$ 2.0

(a) See Note 2 - New Accounting Pronouncements for additional information.

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Income (Loss)	(0.2)
Balance in AOCI as of March 31, 2017	$ 2.8

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Income (Loss)	(0.2)
ASU 2018-02 Adoption (a)	0.5
Balance in AOCI as of March 31, 2018	$ 2.9

(a) See Note 2 - New Accounting Pronouncements for additional information.

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedge - Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)
Net Current Period Other Comprehensive Income (Loss)	(0.2)
Balance in AOCI as of March 31, 2017	$ 3.2

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SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2018

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$(6.0)	$ 2.0	$(4.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.5	(0.4)	0.1
Income Tax (Expense) Credit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.4	(0.3)	0.1
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.3)	0.1
ASU 2018-02 Adoption (a)	(1.3)	0.4	(0.9)
Balance in AOCI as of March 31, 2018	$(6.9)	$ 2.1	$(4.8)

(a) See Note 2 - New Accounting Pronouncements for additional information.

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2017

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(7.4)	$ (2.0)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	0.7	—	0.7
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.7	(0.3)	0.4
Income Tax (Expense) Credit	0.2	(0.1)	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.5	(0.2)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.5	(0.2)	0.3

Balance in AOCI as of March 31, 2017	$(6.9)	$(2.2)	$(9.1)

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4. RATE MATTERS

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

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

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

	AEP	
Noncurrent Regulatory Assets	March 31, 2018	December 31, 2017
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	12.5	9.6
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs (a)	130.3	128.0
Plant Retirement Costs - Asset Retirement Obligation Costs	39.7	39.7
Cook Plant Uprate Project	31.1	36.3
Cook Plant Turbine	11.2	15.9
Other Regulatory Assets Pending Final Regulatory Approval	32.6	42.2
Total Regulatory Assets Pending Final Regulatory Approval (b)	$307.7	$ 322.0

(a) As of March 31, 2018, AEP Texas has deferred $105 million related to Hurricane Harvey and is currently exploring recovery options, including securitization.

(b) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. APCo’s recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC’s 2020 triennial review of APCo’s generation and distribution base rates. The Virginia SCC staff has requested that APCo prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018.

	AEP Texas	
	March 31, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	$128.7	$ 123.3
Rate Case Expense	0.2	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$128.9	$ 123.4

(a) As of March 31, 2018, AEP Texas has deferred $105 million related to Hurricane Harvey and is currently exploring recovery options, including securitization.

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

(a) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. APCo’s recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC’s 2020 triennial review of APCo’s generation and distribution base rates. The Virginia SCC staff has requested that APCo prepare a depreciation study as of December 31, 2017 and submit that study to the Virginia SCC staff in 2018.

	I&M	
	March 31, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Uprate Project	$31.1	$ 36.3
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	—	14.7
Cook Plant Turbine	11.2	15.9
Rockport Dry Sorbent Injection System - Indiana	11.3	10.4
Other Regulatory Assets Pending Final Regulatory Approval	4.5	2.0
Total Regulatory Assets Pending Final Regulatory Approval	$58.1	$ 79.3

	PSO	
	March 31,	December 31,

Noncurrent Regulatory Assets	2018	2017
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$—	$ 3.2
Other Regulatory Assets Pending Final Regulatory Approval	0.1	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$0.1	$ 3.3

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	SWEPCo	
	March 31, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.5
Regulatory Assets Currently Not Earning a Return		
Rate Case Expense - Texas	4.4	4.3
Asset Retirement Obligation - Arkansas, Louisiana	4.3	4.0
Shipe Road Transmission Project - FERC	3.3	3.3
Other Regulatory Assets Pending Final Regulatory Approval	2.8	2.5
Total Regulatory Assets Pending Final Regulatory Approval	$65.6	$ 64.9

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

Impact of Tax Reform

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

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

AEP Texas Interim Transmission and Distribution Rates

As of March 31, 2018, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2017, subject to review, are estimated to be $830 million. A base rate review could produce a refund if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

In March 2018, AEP Texas filed an application to reduce its transmission rates by $24 million to reflect the lower federal income tax rate due to Tax Reform. The filing did not address the return of excess deferred income tax benefits to customers.

In April 2018, AEP Texas filed an application to amend its Distribution Cost Recovery Factor (DCRF). The filing sought to increase revenues by approximately $3 million, which includes capital investment additions of $24 million offset by a reduction of $21 million due to a lower federal income tax rate as a result of Tax Reform. The filing did not address the return of excess deferred income tax benefits to customers. New rates will be effective September 1, 2018.

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

Hurricane Harvey

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. AEP Texas has a PUCT approved catastrophe reserve in base rates and can defer incremental storm expenses. AEP Texas currently recovers approximately $1 million of storm costs annually through base rates. As of March 31, 2018, the total balance of AEP Texas' deferred storm costs is approximately $129 million, inclusive of approximately $105 million of incremental storm expenses recorded as a regulatory asset related to Hurricane Harvey. As of March 31, 2018, AEP Texas has recorded approximately $186 million of capital expenditures related to Hurricane Harvey. Also, as of March 31, 2018, AEP Texas has received $10 million in insurance proceeds, which were applied to the regulatory asset and property, plant and equipment. 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 AEP Texas is currently evaluating recovery options for the regulatory asset, including securitization. The standard process for storm cost recovery in Texas requires two filings with the PUCT. Management expects the first filing by the end of the third quarter of 2018. If the ultimate costs of the incident are not recovered by insurance or through the regulatory process, it would have an adverse effect on future net income, cash flows and financial condition.

APCo Rate Matters (Applies to AEP and APCo)

Virginia Legislation Affecting 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 will: (a) on a one-time basis, require APCo to exclude $10 million of fuel expenses from the July 2018 over/under calculation, (b) reduce APCo's base rates by $50 million annually no later than July 30, 2018, on an interim basis and subject to true-up, to reflect the lower federal income tax rate due to Tax Reform, (c) 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) 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) require APCo to obtain 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 from July 1, 2018 through July 1, 2028 and (f) require APCo to construct and/or acquire solar generation facilities in Virginia of at least 200 MW of aggregate capacity. Triennial reviews are subject to an earnings test which provides that any over earnings may be reinvested in approved energy distribution grid transformation projects. The Virginia SCC's triennial review of 2017-2019 APCo earnings could reduce future net income and cash flows and impact financial condition.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. Through March 31, 2018, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $781 million. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In February 2018, ETT filed an application to reduce its transmission rates by $27 million to reflect the lower federal income tax rate due to Tax Reform. The filing did not address the return of excess deferred income tax benefits to customers.

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

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

2017 Indiana Base Rate Case

In July 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity with the annual increase to be implemented after June 2018. Upon implementation, this proposed annual increase would be subject to a temporary offsetting $23 million annual reduction to customer bills through December 2018 for a credit adjustment rider related to the timing of estimated in-service dates of certain capital expenditures. The proposed annual increase includes $78 million related to increased annual depreciation rates and an $11 million increase related to the amortization of certain Cook Plant and Rockport Plant regulatory assets. The increase in depreciation rates includes a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant, including the Cook Plant Life Cycle Management Project.

In November 2017, various intervenors filed testimony that included annual revenue increase recommendations ranging from $125 million to $152 million. The recommended returns on common equity ranged from 8.65% to 9.1%. In addition, certain parties recommended longer recovery periods than I&M proposed for recovery of regulatory assets and depreciation expenses related to Rockport Plant, Units 1 and 2. In January 2018, in response to a January 2018 IURC request related to the impact of Tax Reform on I&M's pending base rate case, I&M filed updated schedules supporting a $191 million annual increase in Indiana base rates if the effect of Tax Reform was included in the cost of service.

In February 2018, I&M and all parties to the case, except one industrial customer, 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 one industrial customer agreed to not oppose the Stipulation and Settlement Agreement. The difference between I&M's requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement is primarily a result of: (a) the reduction in the federal income tax rate due to Tax Reform, (b) the feedback of credits for excess deferred income taxes, (c) a 9.95% return on equity, (d) longer recovery periods of regulatory assets, (e) lower depreciation expense primarily for meters and (f) an increase in the sharing of off-system sales margins with customers from 50% to 95%. If the Stipulation and Settlement is approved, I&M will also refund $4 million from July through December 2018 for the impact of Tax Reform for the period January through June 2018. A hearing at the IURC was held in March 2018 and an IURC order is expected in the second quarter of 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Michigan Base Rate Case

In May 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity with the increase to be implemented no later than April 2018. The proposed annual increase includes $23 million related to increased annual depreciation rates and a $4 million increase related to the amortization of certain Cook Plant regulatory assets. The increase in depreciation rates is primarily due to the proposed change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028 combined with increased investment at the Cook Plant related to the Life Cycle Management Project.

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenors' proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day and 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 until adjusted in the next base rate case.

In April 2018, the MPSC issued an order that generally approved the ALJ proposal resulting in an annual revenue increase of $49 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.

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 by December 2019. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. As of March 31, 2018, total costs incurred related to this project, including AFUDC, were approximately $28 million. The filing included a request for authorization for I&M to defer its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider in a future filing subsequent to approval of the SCR project. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

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 accounting for 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 I&M's existing Indiana Clean Coal Technology Rider.

In April 2018, a group of intervenors filed a Petition for Reconsideration and Rehearing of the March 2018 IURC order. The intervenors requested that the IURC reopen the proceeding primarily to address whether allowing I&M any cost recovery for the SCR would constitute a cross-subsidization issue and to reverse its finding approving cost recovery for the Rockport Plant, Unit 2 SCR project. Also in April 2018, I&M filed a response to the intervenors' petition.

KPCo Rate Matters (Applies to AEP)

2017 Kentucky Base Rate Case

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

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

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio Electric Security Plan Filings

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

In 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the DIR, effective June 2015 through May 2018. The proposal also involved a PPA rider that would include OPCo's OVEC contractual entitlement (OVEC PPA) and would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA.

In 2015 and 2016, the PUCO issued orders in this proceeding. As part of the issued orders, the PUCO approved (a) the DIR with modified rate caps, (b) recovery of OVEC-related net margin incurred beginning June 2016, (c) potential additional contingent customer credits of up to $15 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MWs and a wind energy project(s) of at least 500 MWs, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. In December 2016, in accordance with the stipulation agreement, OPCo filed a carbon reduction plan that focused on fuel diversification and carbon emission reductions. In April 2017, the PUCO rejected all pending rehearing requests. In June 2017, intervenors filed appeals to the Supreme Court of Ohio stating that the PUCO's approval of the OVEC PPA was unlawful and does not provide customers with rate stability.

In November 2016, OPCo refiled its amended ESP extension application and supporting testimony, consistent with the terms of the modified and approved stipulation agreement and based upon a 2016 PUCO order. The amended filing proposed to extend the ESP through May 2024 and included (a) an extension of the OVEC PPA rider, (b) a proposed 10.41% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) proposed increases in rate caps related to OPCo's DIR and (e) the addition of various new riders, including a Renewable Resource Rider.

In August 2017, OPCo and various intervenors filed a stipulation agreement with the PUCO. The stipulation extends the term of the ESP through May 2024 and includes: (a) an extension of the OVEC PPA rider, (b) a proposed 10% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) rate caps related to OPCo's DIR ranging from $215 million to $290 million for the periods 2018 through 2021 and (e) the addition of various new riders, including a Smart City Rider and a Renewable Generation Rider. DIR rate caps will be reset in OPCo's next distribution base rate case which must be filed by June 2020.

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

In April 2018, the PUCO issued an order approving the stipulation agreement, with no significant changes.

2016 SEET Filing

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

In December 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In May 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016 based upon actual earnings data for the comparable utilities risk group.

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

A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the second half of 2018. 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.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of previously recorded regulatory disallowances in 2013. The resulting annual base rate increase was approximately $52 million. In June 2017, the Texas District Court upheld the PUCT's 2014 order. In July 2017, intervenors filed appeals with the Texas Third Court of Appeals. In April 2018, oral arguments were heard by the Texas Third Court of Appeals.

If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. 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 additional vegetation management expenses and (d) the rejection of SWEPCo’s proposed transmission cost recovery mechanism.

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As a result of the final order, in 2017 SWEPCo (a) recorded an impairment charge of $19 million, which includes $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 expenses. 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. This order is subject to appeal as early as the second quarter 2018. 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 deferred income tax benefits to customers.

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which was effective August 2015. In February 2018, LPSC staff filed a report approving the increase as filed. This increase is subject to refund pending commission approval. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2017 Louisiana Formula Rate Filing

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

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 will be effective August 2018. The filing included a reduction in the federal income tax rate due to Tax Reform. The return of excess deferred income tax benefits to customers will be addressed in a supplemental filing and will reduce the $28 million annual increase. The increase includes SWEPCo’s jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls, whose prudence review hearing is scheduled for May 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could total approximately $850 million, excluding AFUDC. As of March 31, 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 March 31, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $625 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 $11 million, excluding $6 million of unrecognized equity as of March 31, 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. In January 2018, SWEPCo received written approval from the PUCT to recover its project costs from retail customers in its 2016 Texas base rate case and is recovering these costs from wholesale customers through SWEPCo's FERC-approved agreements. See "2016 Texas Base Rate Case" and "2017 Louisiana Formula Rate Filing" disclosures above.

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

FERC Rate Matters

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

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

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

In October 2016, 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, to be 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 accumulated deferred income taxes that are 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, pending the FERC's consideration of the settlement, and the 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. In addition, the FERC trial staff filed comments recommending a base ROE of 8.41% and one-time refund of $175 million. Also in April 2018, another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. Management intends to file reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement.

Management believes the $50 million refund in the settlement agreement is the best estimate of the probable liability. If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition. A decision from the FERC is pending.

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

In November 2016, AEP's transmission owning subsidiaries within PJM filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. In March 2017, the FERC accepted the proposed modifications effective January 1, 2017, subject to refund, and set this matter for hearing and settlement procedures. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In December 2017, AEP's transmission owning subsidiaries within PJM filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In April 2018, the FERC approved the uncontested settlement agreement and rates were implemented effective January 1, 2018.

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

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

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

In October 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected 2018 calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

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

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

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

GUARANTEES

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

Letters of Credit (Applies to AEP and OPCo)

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

AEP has a $3 billion revolving credit facility due in June 2021, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of March 31, 2018, no letters of credit were issued under the $3 billion revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $305 million. In March 2018, one of the uncommitted credit facilities was reduced by $40 million. The Registrants’ maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2018 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 81.3	May 2018 to March 2019
OPCo	0.6	September 2018

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

Guarantees of Third-Party Obligations (Applies to AEP and SWEPCo)

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $140 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. It is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of $77 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of March 31, 2018, SWEPCo has collected $72 million through a rider for final mine closure and reclamation costs, of which $77 million is recorded in Asset Retirement Obligations, offset by $5 million that is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheet.

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

Guarantees of Equity Method Investees (Applies to AEP)

In December 2016, AEP issued a performance guarantee for a 50% owned joint venture which is accounted for as an equity method investment. If the joint venture were to default on payments or performance, AEP would be required to make payments on behalf of the joint venture. As of March 31, 2018, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2018, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2018, the maximum potential loss by Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss

	(in millions)
AEP	$ 43.4
AEP Texas	10.5
APCo	8.8
I&M	3.1
OPCo	6.3
PSO	3.7
SWEPCo	3.7

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

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $7 million and $8 million for I&M and SWEPCo, respectively, for the remaining railcars as of March 31, 2018.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from 83% of the projected fair value of the equipment under the current five year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are $8 million and $9 million for I&M and SWEPCo, respectively, as of March 31, 2018, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. Certain of the boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2027. As of March 31, 2018, the maximum potential amount of future payments required under the guaranteed leases was $49 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of March 31, 2018, AEP's boat and barge lease guarantee liability was $7 million, of which $2 million was recorded in Other Current Liabilities and $5 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

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

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrants currently incur costs to dispose of these substances safely. For remediation processes not specifically discussed, management does not anticipate that the liabilities, if any, arising from such remediation processes would have a material effect on the financial statements.

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

I&M owns and operates the two-unit 2,278 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. As part of the reorganization, the bankruptcy court approved Westinghouse's sale of its nuclear business to Brookfield WEC Holdings, a nonaffiliated third party. Pursuant to the sale, Brookfield will assume all of I&M's contracts with Westinghouse. The sale is subject to regulatory approvals and is expected to close in the third quarter of 2018.

OPERATIONAL CONTINGENCIES

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

In July 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiffs further allege that the defendants' actions constitute breach of the lease and participation agreement. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M.

In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiffs' claims, including the dismissal without prejudice of plaintiffs' claims seeking compensatory damages. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiffs subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiffs' motion for partial judgment and filed a motion to dismiss the case for failure to state a claim.

In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, plaintiffs filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether AEGCo and I&M are in breach of certain contract provisions that plaintiffs allege operate to protect the plaintiffs' residual interests in the unit and whether the trial court erred in dismissing plaintiffs' claims that AEGCo and I&M breached the covenant of good faith and fair dealing.

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

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio 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. 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.

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

Gavin Landfill Litigation (Applies to AEP and OPCo)

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill. As a result of OPCo transferring its generation assets to AGR, the outcome of this complaint became the responsibility of AGR. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors. Twelve of the family members pursued personal injury/illness claims (non-working direct claims) and the remainder pursued loss of consortium claims. The plaintiffs sought compensatory and punitive damages, as well as medical monitoring. In September 2014, defendants filed a motion to dismiss the complaint, contending the case should be filed in Ohio. In August 2015, the court denied the motion. Defendants appealed that decision to the West Virginia Supreme Court. In February 2016, a decision was issued by the court denying the appeal and remanding the case to the West Virginia Mass Litigation Panel (WVMLP), rather than back to the Mason County, West Virginia Circuit Court. Defendants subsequently filed a motion to dismiss the twelve non-working direct claims under Ohio law. The WVMLP denied the motion and defendants again appealed to the West Virginia Supreme Court. In June 2017, the West Virginia Supreme Court reversed the WVMLP decision and dismissed the claims of the twelve non-working direct claim plaintiffs. In April 2018, a settlement in principle was reached. This settlement, once finalized, will be subject to court approval. Management believes the provision recorded for this case is adequate.

6. DISPOSITIONS AND IMPAIRMENTS

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

DISPOSITIONS

Zimmer Plant (Generation & Marketing Segment)

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to a nonaffiliated party. The transaction closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition. The Income before Income Tax Expense and Equity Earnings of Zimmer Plant was immaterial for the three months ended March 31, 2017.

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

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby Plants as well as AEGCo's Lawrenceburg Plant totaling 5,329 MWs of competitive generation assets to a nonaffiliated party. The sale closed in January 2017 for $2.2 billion, which was recorded in Investing Activities on the statement of cash flows. The net proceeds from the transaction were $1.2 billion in cash after taxes, repayment of debt associated with these assets including a make whole payment related to the debt, payment of a coal contract associated with one of the plants and transaction fees. The sale resulted in a pretax gain of $227 million that was recorded in Gain on Sale of Merchant Generation Assets on AEP's statement of income for the three months ended March 31, 2017.

IMPAIRMENTS

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

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

Merchant Generating Assets (Generation & Marketing Segment)

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

7. BENEFIT PLANS

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

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

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans:

AEP

	Pension Plans Three Months Ended March 31,		OPEB Three Months Ended March 31,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$24.4	$24.1	$2.9	$2.8
Interest Cost	46.9	50.8	11.8	14.8
Expected Return on Plan Assets	(72.5)	(71.2)	(25.5)	(25.3)
Amortization of Prior Service Cost (Credit)	—	0.3	(17.3)	(17.3)
Amortization of Net Actuarial Loss	21.3	20.7	2.6	9.2
Net Periodic Benefit Cost (Credit)	$20.1	$24.7	$(25.5)	$(15.8)

AEP Texas

	Pension Plans Three Months Ended March 31,		OPEB Three Months Ended March 31,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.1	$0.3	$0.2
Interest Cost	4.0	4.3	0.9	1.2
Expected Return on Plan Assets	(6.4)	(6.3)	(2.1)	(2.2)
Amortization of Prior Service Credit	—	—	(1.5)	(1.4)
Amortization of Net Actuarial Loss	1.8	1.8	0.2	0.8
Net Periodic Benefit Cost (Credit)	$1.7	$1.9	$(2.2)	$(1.4)

APCo

	Pension Plans Three Months Ended March 31,		OPEB Three Months Ended March 31,	

	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.3	$0.3	$0.3
Interest Cost	5.9	6.4	2.0	2.6
Expected Return on Plan Assets	(9.1)	(8.9)	(4.0)	(4.1)
Amortization of Prior Service Cost (Credit)	—	0.1	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.6	2.6	0.5	1.6
Net Periodic Benefit Cost (Credit)	$1.7	$2.5	$(3.7)	$(2.1)

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I&M

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$3.4	$3.5	$0.4	$0.4
Interest Cost	5.5	6.1	1.4	1.7
Expected Return on Plan Assets	(8.9)	(8.6)	(3.1)	(3.1)
Amortization of Prior Service Credit	—	—	(2.4)	(2.3)
Amortization of Net Actuarial Loss	2.5	2.4	0.3	1.1
Net Periodic Benefit Cost (Credit)	$2.5	$3.4	$(3.4)	$(2.2)

OPCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.0	$1.9	$0.2	$0.2
Interest Cost	4.4	4.8	1.3	1.7
Expected Return on Plan Assets	(7.2)	(7.0)	(3.0)	(3.0)
Amortization of Prior Service Credit	—	—	(1.7)	(1.7)
Amortization of Net Actuarial Loss	2.0	2.0	0.3	1.1
Net Periodic Benefit Cost (Credit)	$1.2	$1.7	$(2.9)	$(1.7)

PSO

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$1.8	$1.6	$0.2	$0.2
Interest Cost	2.4	2.7	0.6	0.8
Expected Return on Plan Assets	(4.0)	(3.9)	(1.4)	(1.4)
Amortization of Prior Service Credit	—	—	(1.0)	(1.1)
Amortization of Net Actuarial Loss	1.1	1.1	0.1	0.5
Net Periodic Benefit Cost (Credit)	$1.3	$1.5	$(1.5)	$(1.0)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.2	$0.3	$0.2
Interest Cost	2.9	3.1	0.7	0.9
Expected Return on Plan Assets	(4.4)	(4.2)	(1.6)	(1.6)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.3	1.2	0.1	0.6
Net Periodic Benefit Cost (Credit)	$2.1	$2.3	$(1.8)	$(1.2)

8. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

AEP's reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

- Competitive generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.
- Contracted renewable energy investments and management services.

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

The tables below present AEP's reportable segment income statement information for the three months ended March 31, 2018 and 2017 and reportable segment balance sheet information as of March 31, 2018 and December 31, 2017.

	Three Months Ended March 31, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$2,381.5	$ 1,141.2	$ 41.1	$ 477.5	$ 7.0	$ —	$ 4,048.3
Other Operating Segments	26.5	21.2	164.4	27.6	17.0	(256.7)	—
Total Revenues	$2,408.0	$ 1,162.4	$ 205.5	$ 505.1	$ 24.0	$ (256.7)	$ 4,048.3
Net Income (Loss)	$232.8	$ 125.4	$ 104.8	$ 18.1	$ (24.4)	$ —	$ 456.7

	Three Months Ended March 31, 2017						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$2,269.8	$ 1,066.4	$ 27.7	$ 558.8	$ 10.6	$ —	$ 3,933.3
Other Operating Segments	20.6	20.0	128.4	32.6	15.9	(217.5)	—
Total Revenues	$2,290.4	$ 1,086.4	$ 156.1	$ 591.4	$ 26.5	$ (217.5)	$ 3,933.3
Net Income (Loss)	$220.5	$ 119.1	$ 72.8	$ 186.2	$ (4.4)	$ —	$ 594.2

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	March 31, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$43,749.8	$16,790.4	$7,446.6	$786.9	$377.7	$(355.1) (b)	$68,796.3
Accumulated Depreciation and Amortization	13,355.3	3,809.8	200.1	70.1	182.9	(187.0) (b)	17,431.2
Total Property Plant and Equipment - Net	$30,394.5	$12,980.6	$7,246.5	$716.8	$194.8	$(168.1) (b)	$51,365.1
Total Assets	$37,913.3	$16,272.6	$8,340.5	$2,123.7	$4,552.9 (c)	$(3,593.5) (b) (d)	$65,609.5
Long-term Debt Due Within One Year:							
Nonaffiliated	$1,893.7	$670.6	$50.0	$0.1	$1.7	$—	$2,616.1
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	9,969.2	4,972.4	2,635.0	(0.3)	1,268.6	—	18,844.9
Total Long-term Debt	$11,912.9	$5,643.0	$2,685.0	$32.0	$1,270.3	$(82.2)	$21,461.0

	December 31, 2017						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$43,294.4	$16,371.2	$7,110.2	$644.6	$374.5	$(366.4) (b)	$67,428.5
Accumulated Depreciation and Amortization	13,153.4	3,768.3	176.6	75.0	180.6	(186.9) (b)	17,167.0
Total Property Plant and Equipment - Net	$30,141.0	$12,602.9	$6,933.6	$569.6	$193.9	$(179.5) (b)	$50,261.5
Total Assets	$37,579.7	$16,060.7	$8,141.8	$2,009.8	$3,959.1 (c)	$(3,022.0) (b) (d)	$64,729.1
Long-term Debt Due Within One Year:							
Nonaffiliated	$1,038.1	$663.1	$50.0	$—	$2.5	$—	$1,753.7

Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	10,801.4	4,705.4	2,631.3	(0.3)	1,281.8	—	19,419.6
Total Long-term Debt	$11,889.5	$5,368.5	$2,681.3	$31.9	$1,284.3	$(82.2)	$21,173.3

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

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the three months ended March 31, 2018 and 2017 and reportable segment balance sheet information as of March 31, 2018 and December 31, 2017.

	Three Months Ended March 31, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$31.3	$ —	$ —	$ 31.3
Sales to AEP Affiliates	162.1	—	—	162.1
Other Revenues	0.1	—	—	0.1
Total Revenues	$193.5	$ —	$ —	$ 193.5
Interest Income	$0.2	$ 25.0	$ (24.8) (a)	$ 0.4
Interest Expense	19.9	24.8	(24.8) (a)	19.9
Income Tax Expense	22.3	0.2	—	22.5
Net Income (Loss)	$86.0	$ (0.1) (b)	$ —	$ 85.9

	Three Months Ended March 31, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				

External Customers	$19.2	$ —	$ —	$ 19.2
Sales to AEP Affiliates	133.4	—	—	133.4
Other Revenues	0.1	—	—	0.1
Total Revenues	$152.7	$ —	$ —	$ 152.7
Interest Income	$0.1	$ 19.1	$ (19.0) (a)	$ 0.2
Interest Expense	15.8	19.2	(19.0) (a)	16.0
Income Tax Expense	28.4	0.1	—	28.5
Net Income	$56.8	$ 0.2 (b)	$ —	$ 57.0

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	March 31, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$7,108.0	$—	$—	$ 7,108.0
Accumulated Depreciation and Amortization	192.7	—	—	192.7
Total Transmission Property – Net	$6,915.3	$—	$—	$ 6,915.3
Notes Receivable - Affiliated	$—	$2,550.7	$ (2,550.7) (c)	$ —
Total Assets	$7,220.0	$2,637.3 (d)	$ (2,617.4) (e)	$ 7,239.9
Total Long-term Debt	$2,575.0	$2,550.7	$ (2,575.0) (c)	$ 2,550.7

	December 31, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$6,780.2	$—	$—	$ 6,780.2
Accumulated Depreciation and Amortization	170.4	—	—	170.4
Total Transmission Property – Net	$6,609.8	$—	$—	$ 6,609.8
Notes Receivable - Affiliated	$—	$2,550.4	$ (2,550.4) (c)	$ —
Total Assets	$7,072.9	$2,590.1 (d)	$ (2,594.9) (e)	$ 7,068.1
Total Long-term Debt	$2,575.0	$2,550.4	$ (2,575.0) (c)	$ 2,550.4

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos.
(c) Elimination of intercompany debt.
(d) Includes the elimination of AEPTCo Parent's investments in State Transcos.
(e) Primarily relates to the elimination of Notes Receivable from the State Transcos.

9. DERIVATIVES AND HEDGING

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk, credit risk and foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, the Registrants primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

The Registrants utilize power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following tables represent the gross notional volume of the Registrants’ outstanding derivative contracts:

Notional Volume of Derivative Instruments
March 31, 2018

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)						
Commodity:								
Power	MWhs	298.4	—	43.2	33.0	8.3	4.0	8.1
Coal	Tons	1.2	—	—	1.2	—	—	—
Natural Gas	MMBtus	78.2	—	6.2	3.7	—	—	18.0
Heating Oil and Gasoline	Gallons	5.0	1.1	1.0	0.5	1.2	0.5	0.6
Interest Rate	USD	$49.8	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$500.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2017

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)						
Commodity:								
Power	MWhs	358.7	—	57.4	38.5	10.4	10.3	22.7
Coal	Tons	2.0	—	—	2.0	—	—	—
Natural Gas	MMBtus	53.7	—	1.1	0.7	—	—	18.3
Heating Oil and Gasoline	Gallons	6.9	1.4	1.3	0.7	1.6	0.7	0.8
Interest Rate	USD	$50.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$500.0	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power (“Commodity”) in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

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

At times, the Registrants are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, the Registrants may utilize foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrants do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for “Derivatives and Hedging” requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrants apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract’s term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management’s estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for “Derivatives and Hedging,” the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. AEP netted cash collateral received from third parties against short-term and long-term risk management assets in the amounts of $1 million and $9.4 million as of March 31, 2018 and December 31, 2017, respectively. AEP netted cash collateral paid to third parties against short-term and long-term risk management liabilities in the amounts of $18 million and $9 million as of March 31, 2018 and December 31, 2017, respectively. The netted cash collateral from third parties against short-term and long-term risk management assets and netted cash collateral paid to third parties against short-term and long-term risk management liabilities were immaterial for the other Registrants as of March 31, 2018 and December 31, 2017.

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

AEP

Fair Value of Derivative Instruments
March 31, 2018

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$257.0	$20.1	$1.7	$ 278.8	$(189.2)	$ 89.6
Long-term Risk Management Assets	319.6	5.1	—	324.7	(53.5)	271.2
Total Assets	576.6	25.2	1.7	603.5	(242.7)	360.8
Current Risk Management Liabilities	246.8	10.1	—	256.9	(199.8)	57.1
Long-term Risk Management Liabilities	271.6	48.5	22.3	342.4	(59.7)	282.7
Total Liabilities	518.4	58.6	22.3	599.3	(259.5)	339.8
Total MTM Derivative Contract Net Assets (Liabilities)	$58.2	$(33.4)	$(20.6)	$ 4.2	$16.8	$ 21.0

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$389.0	$17.5	$2.5	$ 409.0	$(282.8)	$ 126.2
Long-term Risk Management Assets	300.9	6.3	—	307.2	(25.1)	282.1
Total Assets	689.9	23.8	2.5	716.2	(307.9)	408.3
Current Risk Management Liabilities	334.6	9.0	—	343.6	(282.0)	61.6
Long-term Risk Management Liabilities	280.6	58.3	8.6	347.5	(25.5)	322.0
Total Liabilities	615.2	67.3	8.6	691.1	(307.5)	383.6
Total MTM Derivative Contract Net Assets (Liabilities)	$74.7	$(43.5)	$(6.1)	$ 25.1	$(0.4)	$ 24.7

AEP Texas
Fair Value of Derivative Instruments
March 31, 2018

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

Fair Value of Derivative Instruments
December 31, 2017

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

APCo
Fair Value of Derivative Instruments
March 31, 2018
Balance Sheet Location

	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$35.8	$ (27.8)	$ 8.0
Long-term Risk Management Assets	11.2	(8.6)	2.6
Total Assets	47.0	(36.4)	10.6
Current Risk Management Liabilities	28.4	(27.8)	0.6
Long-term Risk Management Liabilities	9.1	(8.7)	0.4
Total Liabilities	37.5	(36.5)	1.0
Total MTM Derivative Contract Net Assets	$9.5	$ 0.1	$ 9.6

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$75.6	$ (50.7)	$ 24.9
Long-term Risk Management Assets	2.4	(1.3)	1.1
Total Assets	78.0	(52.0)	26.0
Current Risk Management Liabilities	50.6	(49.3)	1.3
Long-term Risk Management Liabilities	1.4	(1.2)	0.2
Total Liabilities	52.0	(50.5)	1.5
Total MTM Derivative Contract Net Assets (Liabilities)	$26.0	$ (1.5)	$ 24.5

I&M
Fair Value of Derivative Instruments
March 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$24.0	$ (20.7)	$ 3.3
Long-term Risk Management Assets	8.0	(6.0)	2.0
Total Assets	32.0	(26.7)	5.3
Current Risk Management Liabilities	24.6	(20.8)	3.8
Long-term Risk Management Liabilities	6.1	(5.9)	0.2
Total Liabilities	30.7	(26.7)	4.0
Total MTM Derivative Contract Net Assets	$1.3	$ —	$ 1.3

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$47.2	$ (39.6)	$ 7.6
Long-term Risk Management Assets	1.6	(0.9)	0.7
Total Assets	48.8	(40.5)	8.3
Current Risk Management Liabilities	48.5	(45.0)	3.5
Long-term Risk Management Liabilities	0.9	(0.8)	0.1
Total Liabilities	49.4	(45.8)	3.6
Total MTM Derivative Contract Net Assets (Liabilities)	$(0.6)	$ 5.3	$ 4.7

OPCo
Fair Value of Derivative Instruments
March 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.5	$ (0.1)	$ 0.4
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	(0.1)	0.4
Current Risk Management Liabilities	5.3	—	5.3
Long-term Risk Management Liabilities	93.2	—	93.2
Total Liabilities	98.5	—	98.5
Total MTM Derivative Contract Net Liabilities	$(98.0)	$ (0.1)	$ (98.1)

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6
Current Risk Management Liabilities	6.4	—	6.4
Long-term Risk Management Liabilities	126.0	—	126.0
Total Liabilities	132.4	—	132.4
Total MTM Derivative Contract Net Liabilities	$(131.8)	$ —	$ (131.8)

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PSO
Fair Value of Derivative Instruments
March 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$2.9	$ —	$ 2.9
Long-term Risk Management Assets	—	—	—
Total Assets	2.9	—	2.9
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$2.9	$ —	$ 2.9

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$6.6	$ (0.2)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.6	(0.2)	6.4
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets	$6.4	$ —	$ 6.4

SWEPCo
Fair Value of Derivative Instruments
March 31, 2018
Balance Sheet Location

	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$2.8	$ (1.1)	$ 1.7
Long-term Risk Management Assets	—	—	—
Total Assets	2.8	(1.1)	1.7
Current Risk Management Liabilities	1.2	(1.1)	0.1
Long-term Risk Management Liabilities	0.5	—	0.5
Total Liabilities	1.7	(1.1)	0.6
Total MTM Derivative Contract Net Assets	$1.1	$ —	$ 1.1

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$7.0	$ (0.6)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	7.0	(0.6)	6.4
Current Risk Management Liabilities	0.8	(0.6)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.8	(0.6)	0.2
Total MTM Derivative Contract Net Assets	$6.2	$ —	$ 6.2

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

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for “Derivatives and Hedging.”

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

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

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Three Months Ended March 31, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$(5.5)	$—	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	(15.1)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.3)	(5.1)	—	—	—
Purchased Electricity for Resale	4.9	—	4.6	0.2	—	—	—
Other Operation	0.3	0.1	—	—	0.1	—	—
Maintenance	0.4	0.1	0.1	—	0.1	—	—
Regulatory Assets (a)	37.3	—	—	6.2	31.4	—	(0.3)
Regulatory Liabilities (a)	87.0	(0.1)	64.1	0.2	—	12.1	(0.8)
Total Gain (Loss) on Risk Management Contracts	$109.3	$0.1	$68.5	$1.5	$31.6	$12.1	$ (1.1)

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Three Months Ended March 31, 2017

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$5.5	$—	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	10.5	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.4	5.2	—	—	0.1
Purchased Electricity for Resale	2.4	—	0.8	0.1	—	—	—
Other Operation	0.2	—	—	—	—	—	—
Maintenance	0.2	—	—	—	—	—	—
Regulatory Assets (a)	(14.9)	—	(5.8)	(0.2)	(8.6)	—	(0.2)
Regulatory Liabilities (a)	25.2	(0.2)	10.9	6.8	—	2.4	4.6
Total Gain (Loss) on Risk Management Contracts	$29.1	$(0.2)	$6.3	$11.9	$(8.6)	$2.4	$ 4.5

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

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

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income.

Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.”

Accounting for Fair Value Hedging Strategies (Applies to AEP)

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income. The following table shows the results of hedging gains (losses):

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Loss on Fair Value Hedging Instruments	$(14.5)	$(0.5)
Gain on Fair Value Portion of Long-term Debt	14.2	0.5

During the three months ended March 31, 2018 and 2017, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. The Registrants recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness would be recorded as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2018 and 2017, AEP applied cash flow hedging to outstanding power derivatives. During the three months ended March 31, 2018 and 2017, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2018 and 2017, the Registrants did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2018 and 2017, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

During the three months ended March 31, 2018 and 2017, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

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

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	March 31, 2018		December 31, 2017	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
Hedging Assets (a)	$ 25.5	$ —	$ 22.0	$ —
Hedging Liabilities (a)	58.9	—	65.5	—
AOCI Loss Net of Tax	(32.0)	(15.5)	(28.4)	(13.0)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3.1	(1.0)	5.5	(0.8)

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

As of March 31, 2018 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 117 months.

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

	March 31, 2018		December 31, 2017	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (5.2)	$ (1.1)	$ (4.5)	$ (0.9)
APCo	2.5	0.9	2.2	0.7
I&M	(12.7)	(1.6)	(10.7)	(1.3)
OPCo	2.0	1.3	1.9	1.1
PSO	2.9	1.0	2.6	0.8
SWEPCo	(6.9)	(1.7)	(6.0)	(1.4)

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses Moody's Investors Service Inc., S&P Global Inc. and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. A counterparty is required to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination
and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Collateral Triggering Events

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

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had immaterial derivative contracts with collateral triggering events in a net liability position as of March 31, 2018 and December 31, 2017, respectively.

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

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	AEP		
	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
	(in millions)		
March 31, 2018	$272.7	$ 1.0	$ 202.4
December 31, 2017	243.6	1.3	223.1

Amounts for APCo, I&M and SWEPCo are immaterial as of March 31, 2018 and December 31, 2017, respectively.

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

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

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

Fair Value Measurements of Long-term Debt (Applies to all Registrants)

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

Company	March 31, 2018 Book Value	March 31, 2018 Fair Value	December 31, 2017 Book Value	December 31, 2017 Fair Value
	(in millions)			
AEP	$21,461.0	$23,039.8	$21,173.3	$23,649.6
AEP Texas	3,553.3	3,818.3	3,649.3	3,964.8
AEPTCo	2,550.7	2,620.6	2,550.4	2,782.9
APCo	3,969.3	4,532.0	3,980.1	4,782.6
I&M	2,717.2	2,869.5	2,745.1	3,014.7
OPCo	2,089.7	2,367.9	1,719.3	2,064.3
PSO	1,286.7	1,400.3	1,286.5	1,457.1
SWEPCo	2,503.7	2,587.3	2,441.9	2,645.9

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

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

The following is a summary of Other Temporary Investments:

Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	March 31, 2018			
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$162.0	$ —	$ —	$162.0
Fixed Income Securities – Mutual Funds (b)	104.8	—	(2.2)	102.6
Equity Securities – Mutual Funds	17.2	19.2	—	36.4
Total Other Temporary Investments	$284.0	$ 19.2	$ (2.2)	$301.0

Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	December 31, 2017			
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$220.1	$ —	$ —	$220.1
Fixed Income Securities – Mutual Funds (b)	104.3	—	(1.4)	102.9
Equity Securities – Mutual Funds	17.0	19.7	—	36.7
Total Other Temporary Investments	$341.4	$ 19.7	$ (1.4)	$359.7

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

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Proceeds from Investment Sales	$ —	$ —
Purchases of Investments	0.6	0.5
Gross Realized Gains on Investment Sales	—	—
Gross Realized Losses on Investment Sales	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three months ended March 31, 2017, see Note 3 - Comprehensive Income.

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

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Upon adoption of ASU 2016-01 in first quarter 2018, equity securities are now recorded with changes in fair value recognized in earnings. Effective January 2018 available for sale classification only applies to investment in debt securities. Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI.

The following is a summary of nuclear trust fund investments:

	March 31, 2018			December 31, 2017		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$16.4	$ —	$ —	$17.2	$ —	$ —
Fixed Income Securities:						
United States Government	974.6	19.0	(8.4)	981.2	29.7	(3.6)
Corporate Debt	57.8	2.0	(1.7)	58.7	3.8	(1.2)
State and Local Government	8.6	0.6	(0.2)	8.8	0.8	(0.2)
Subtotal Fixed Income Securities	1,041.0	21.6	(10.3)	1,048.7	34.3	(5.0)
Equity Securities – Domestic (a)	1,453.2	850.3	—	1,461.7	868.2	(75.5)
Spent Nuclear Fuel and Decommissioning Trusts	$2,510.6	$ 871.9	$ (10.3)	$2,527.6	$ 902.5	$ (80.5)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $855 million and unrealized losses of $4.7 million. AEP adopted ASU 2016-01 during the first quarter of 2018 by means of a modified retrospective approach. Due to the adoption of the ASU, Other-Than-Temporary Impairments are no longer applicable to Equity Securities with readily determinable fair values.

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

	Three Months Ended March 31,	
	2018	2017
	(in millions)	
Proceeds from Investment Sales	$508.6	$487.9
Purchases of Investments	525.3	505.5
Gross Realized Gains on Investment Sales	12.0	11.3
Gross Realized Losses on Investment Sales	10.9	8.1

The base cost of fixed income securities was $1 billion and $1 billion as of March 31, 2018 and December 31, 2017, respectively. The base cost of equity securities was $603 million and $594 million as of March 31, 2018 and December 31, 2017, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of March 31, 2018 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 355.7
After 1 year through 5 years	315.3
After 5 years through 10 years	205.8
After 10 years	164.2
Total	$ 1,041.0

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Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$144.8	$—	$—	$17.2	$162.0
Fixed Income Securities – Mutual Funds	102.6	—	—	—	102.6
Equity Securities – Mutual Funds (b)	36.4	—	—	—	36.4
Total Other Temporary Investments	283.8	—	—	17.2	301.0
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.0	265.0	243.3	(177.7)	333.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	11.6	3.1	10.8	25.5
Fair Value Hedges	—	1.7	—	—	1.7
Total Risk Management Assets	3.0	278.3	246.4	(166.9)	360.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9.1	—	—	7.3	16.4
Fixed Income Securities:					
United States Government	—	974.6	—	—	974.6
Corporate Debt	—	57.8	—	—	57.8
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,041.0	—	—	1,041.0
Equity Securities – Domestic (b)	1,453.2	—	—	—	1,453.2
Total Spent Nuclear Fuel and Decommissioning Trusts	1,462.3	1,041.0	—	7.3	2,510.6
Total Assets	$1,749.1	$1,319.3	$246.4	$(142.4)	$3,172.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$3.6	$284.7	$164.8	$(194.5)	$258.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	28.5	19.6	10.8	58.9

Fair Value Hedges	—	22.3	—	—	22.3
Total Risk Management Liabilities	$3.6	$335.5	$184.4	$(183.7)	$339.8

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AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$183.2	$—	$—	$36.9	$220.1
Fixed Income Securities – Mutual Funds	102.9	—	—	—	102.9
Equity Securities – Mutual Funds (b)	36.7	—	—	—	36.7
Total Other Temporary Investments	322.8	—	—	36.9	359.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	3.9	391.2	274.1	(285.4)	383.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	17.3	4.7	—	22.0
Fair Value Hedges	—	2.5	—	—	2.5
Total Risk Management Assets	3.9	411.0	278.8	(285.4)	408.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$1,795.9	$1,459.7	$278.8	$(238.8)	$3,295.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$5.1	$392.5	$196.9	$(285.0)	$309.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	23.9	41.6	—	65.5
Fair Value Hedges	—	8.6	—	—	8.6
Total Risk Management Liabilities	$5.1	$425.0	$238.5	$(285.0)	$383.6

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2018

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Restricted Cash for Securitized Funding	$ 107.1	$ —	$ —	$ —	$ 107.1
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.4	—	(0.1)	0.3
Total Assets	$ 107.1	$ 0.4	$ —	$ (0.1)	$ 107.4

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in millions)				
Restricted Cash for Securitized Funding	$ 155.2	$ —	$ —	$ —	$ 155.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.5	—	—	0.5
Total Assets	$ 155.2	$ 0.5	$ —	$ —	$ 155.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$10.1	$—	$—	$—	$10.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	0.6	27.0	10.4	(27.4)	10.6
Total Assets	$10.7	$27.0	$10.4	$(27.4)	$20.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$0.6	$26.6	$1.3	$(27.5)	$1.0

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$16.3	$—	$—	$—	$16.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	52.5	25.1	(51.6)	26.0
Total Assets	$16.3	$52.5	$25.1	$(51.6)	$42.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$51.2	$0.4	$(50.1)	$1.5

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$0.3	$19.4	$5.1	$(19.5)	$5.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9.1	—	—	7.3	16.4
Fixed Income Securities:					
United States Government	—	974.6	—	—	974.6
Corporate Debt	—	57.8	—	—	57.8
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,041.0	—	—	1,041.0
Equity Securities - Domestic (b)	1,453.2	—	—	—	1,453.2
Total Spent Nuclear Fuel and Decommissioning Trusts	1,462.3	1,041.0	—	7.3	2,510.6
Total Assets	$1,462.6	$1,060.4	$5.1	$(12.2)	$2,515.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$0.3	$21.0	$2.2	$(19.5)	$4.0

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017