AMERICAN ELECTRIC POWER CO INC
Form 10-Q
July 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 June 30, 2018
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
333-221643	AEP TEXAS INC. (A Delaware Corporation)	51-0007707
333-217143	AEP TRANSMISSION COMPANY, LLC (A Delaware Limited Liability Company)	46-1125168
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373	
	Telephone (614) 716-1000	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit such files). Yes x No ¨

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

Large Accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

Smaller reporting company ¨ Emerging growth company ¨

Indicate by check mark whether AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x

Smaller reporting company ¨ Emerging growth company ¨

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

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange

Act). Yes
¨ No x

AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

	Number of shares of common stock outstanding of the Registrants as of July 26, 2018
American Electric Power Company, Inc.	492,934,058 ($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
June 30, 2018

Part II. OTHER INFORMATION

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no

representation as to information
relating to the other registrants.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas markets.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns seven wholly-owned transmission companies.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ASC	Accounting Standard Codification.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
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 VII, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X, DCC Fuel XI and DCC Fuel XII consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	

	Desert Sky Wind Farm, a 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.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
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.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SCR	Selective Catalytic Reduction, NO_x reduction technology at Rockport Plant.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
	Legislation enacted in 1999 to restructure the electric utility industry in Texas.

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

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Term	Meaning
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Trent	Trent Wind Farm, a 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 ADIT.

Resolution of litigation.

The ability to constrain operation and maintenance costs.

Prices and demand for power generated and sold at wholesale.

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

The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.

Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.

Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
Actions of rating agencies, including changes in the ratings of debt.
The impact of volatility in the capital markets on the value of the investments held by the pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.

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Accounting pronouncements periodically issued by accounting standard-setting bodies.
Impact of federal tax reform on customer rates, income tax expense and cash flows.
Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2017 Annual Report and in Part II of this report.

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

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

EXECUTIVE OVERVIEW

Customer Demand

AEP’s weather-normalized retail sales volumes for the second quarter of 2018 increased by 2.0% compared to the second quarter of 2017. AEP’s second quarter 2018 industrial sales increased by 3.0% compared to the second quarter of 2017. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential sales increased 2.1% in the second quarter of 2018 compared to the second quarter of 2017. Weather-normalized commercial sales increased by 0.7% in the second quarter of 2018 compared to the second quarter of 2017.

AEP’s weather-normalized retail sales volumes for the six months ended June 30, 2018 increased by 1.7% compared to the six months ended June 30, 2017. AEP’s industrial sales volumes for the six months ended June 30, 2018 increased 2.8% compared to the six months ended June 30, 2017. The growth in industrial sales was spread across many industries and most operating companies. Weather-normalized residential and commercial sales increased 1.7% and 0.6%, respectively, for the six months ended June 30, 2018 compared to the six months ended June 30, 2017.

Wind Catcher Project

In July 2017, PSO and SWEPCo submitted filings with the OCC, LPSC, APSC and PUCT requesting various regulatory approvals needed for the companies to proceed with the Wind Catcher Project. The Wind Catcher Project 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 350 miles. Total investment for the project is estimated to be $4.5 billion and will serve both retail and FERC wholesale load. PSO and SWEPCo will have 30% and 70% ownership shares, respectively, in these assets. The wind generation facility is located in Oklahoma and, if approved by all state commissions, is anticipated to be in-service by the end of 2020. 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.

In February 2018, an 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 settlement discussions. A non-unanimous settlement agreement was filed in Arkansas in February 2018, a unanimous settlement was filed in April 2018 in Louisiana and a non-unanimous settlement was filed in April 2018 in Oklahoma. An amendment to the Joint Stipulation in Oklahoma was filed in May 2018 to include additional parties to the non-unanimous settlement. A separate Joint Stipulation and settlement agreement was reached between PSO and two other parties. 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. In May 2018, the APSC approved SWEPCo’s petition to proceed with the Wind Catcher Project. In June

2018, the LPSC approved SWEPCo's petition to proceed with the Wind Catcher Project. In July 2018, a hearing on the settlement agreements presented in the PSO case was held before the three OCC Commissioners. Also in July 2018, representatives from SWEPCo and AEPSC presented oral arguments before the three PUCT Commissioners. Rulings by the PUCT and OCC are expected in the third quarter of 2018.

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Other Renewable Generation

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

Contracted Renewable Generation Facilities

AEP continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy technologies. Generation & Marketing also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts. As of June 30, 2018, subsidiaries within AEP’s Generation & Marketing segment have approximately 400 MWs of contracted renewable generation projects in operation. In addition, as of June 30, 2018, these subsidiaries have approximately 7 MWs of new renewable generation projects under construction with total estimated capital costs of $16 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. 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 $185 million has been incurred and placed into service as property, plant and equipment as of June 30, 2018. AEP is subject to a put and a call option after certain conditions are met, either of which would liquidate the nonaffiliated member’s interest. See Note 13 - Variable Interest Entities for additional information.

Regulated Renewable Generation Facilities

In July 2017, APCo submitted filings with the Virginia SCC and the WVPSC requesting regulatory approval to acquire two wind generation facilities totaling approximately 225 MWs of wind generation. In April 2018, the Virginia SCC denied APCo’s application to acquire the two wind generation facilities. APCo filed a petition for reconsideration with the Virginia SCC, which was denied. In May 2018, the WVPSC also denied APCo’s application to acquire the two wind generation facilities.

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 second 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 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

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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. As of June 30, 2018, AEP has recorded estimated provisions for revenue refunds totaling $144 million as a result of the reduction in the corporate federal tax rate.

Excess ADIT - Pending Rate Reductions

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

As reflected in the Registrants' respective estimated annual ETR for 2018, AEP's regulated public utilities began amortizing the Excess ADIT associated with certain depreciable property subject to rate normalization requirements using the ARAM during the first quarter of 2018. The amortization resulted in a $33 million reduction in Income Tax Expense for the six months ended June 30, 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 $33 million as of June 30, 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. As a result of certain state utility commission orders or instructions received and a filed FERC settlement agreement, AEP, AEPTCo, APCo, I&M, and OPCo began amortizing Excess ADIT not subject to rate normalization requirements.

Merchant Coal Generation Assets

Management continues to evaluate potential alternatives for its remaining merchant coal 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.

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 of storm costs annually through base rates. As of June 30, 2018, the total balance of AEP Texas’ catastrophe reserve deferral is approximately $145 million, inclusive of approximately $121 million of incremental storm expenses recorded as a regulatory asset related to Hurricane Harvey. As of June 30, 2018, AEP Texas has recorded approximately $199 million of capital expenditures related to Hurricane Harvey. Also, as of June 30, 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 will request securitization of the regulatory asset. The standard process for securitization of storm cost recovery in Texas requires two filings with the PUCT. Management expects that AEP Texas will make 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.

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

In April 2018, the PUCO issued an order approving the ESP extension through May 2024 which includes: (a) an extension of the OVEC PPA rider, (b) a 10% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) 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, effective June 1, 2018, based on a depreciation study using data through December 2015 and (g) amortization of approximately $24 million annually beginning June 2018 of OPCo’s excess distribution accumulated depreciation reserve, which was $239 million as of December 31, 2015. Upon the issuance of the PUCO order, OPCo stopped recording $39 million in annual amortization in June 2018, which was previously approved to end in December 2018 in accordance with PUCO’s December 2011 OPCo distribution base rate case order. OPCo and intervenors agreed that OPCo can request in future proceedings a change in meter depreciation rates due to retired meters pursuant to the smart grid Phase 2 project. DIR rate caps will be reset in OPCo’s next distribution base rate case which must be filed by June 2020.

In May 2018, OPCo and various intervenors filed requests for rehearing with the PUCO. In June 2018, these requests for rehearing were approved to allow further consideration of the requests. See “Ohio Electric Security Plan Filings” section of Note 4 for additional information.

2016 SEET Filing

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

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

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

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

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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. 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 of the Indiana jurisdictional ownership share of costs, including investment carrying costs, (d) depreciation of the SCR asset over 10 years and (e) recovery of these costs using an I&M Indiana rider.

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

2017 Indiana Base Rate Case

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

In February 2018, I&M filed a Stipulation and Settlement Agreement for a $97 million annual increase in Indiana rates effective July 1, 2018 subject to a temporary offsetting reduction to customer bills through December 2018 for a credit rider related to the timing of estimated in-service dates of certain capital expenditures. The difference between I&M’s requested $263 million annual increase and the $97 million annual increase in the Stipulation and Settlement Agreement is primarily a result of: (a) the reduction in the federal income tax rate due to Tax Reform, (b) the feedback of credits for Excess ADIT, (c) a 9.95% return on equity, (d) longer recovery periods of regulatory assets, (e) lower depreciation expense primarily for meters, (f) an increase in the sharing of off-system sales margins with customers from 50% to 95% and (g) a refund of $4 million from July through December 2018 for the impact of Tax Reform for the period January through June 2018.
In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement in its entirety.
2017 Michigan Base Rate Case

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

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In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenors' proposal for up to 10% of I&M's Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day, as well as the MPSC staff's recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a return on common equity of 9.8%. If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million 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 $50 million, effective April 2018 based on a 9.9% return on common equity. The MPSC also approved the ALJ's recommendation related to the capacity rate.

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

Merchant Portion of Turk Plant

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

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-based rates. As of June 30, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. SWEPCo intends to file a request for rehearing with the court of appeals in the third quarter of 2018. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See "2012 Texas Base Rate Case" section of Note 4.

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 by the LPSC. In May 2018, LPSC staff filed testimony that the environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants is prudent. In July 2018, an ALJ recommended the LPSC approve a settlement agreement for the environmental control investment. An order is expected in the third quarter of 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2018 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 increase included SWEPCo's jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

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

2017 Kentucky Base Rate Case

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

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

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

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

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

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included (a) approval to recover the Texas jurisdictional share of environmental investments placed in service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in

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additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

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

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

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 incurred fuel expenses from the July 2018 over/under recovery calculation, (b) reduce APCo's base rates by $50 million annually commencing 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 seek approval from the Virginia SCC for energy efficiency programs with projected costs in the aggregate of at least $140 million over the 10-year period ending July 1, 2028 and (f) require APCo to construct and/or acquire solar generation facilities in Virginia, as approved by the Virginia SCC, of at least 200 MW of aggregate capacity by July 1, 2028. Triennial reviews are subject to an earnings test which provides that 70% of any over earnings would be refunded or may be reinvested in approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. The Virginia SCC's triennial review of 2017-2019 APCo earnings could reduce future net income and cash flows and impact financial condition.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase includes $32 million ($28 million related to APCo) due to increased annual depreciation rates and also reflects the impact of the reduction in the federal income tax rate due to Tax Reform. A hearing at the WVPSC is scheduled for November 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission Complaint - AEP's PJM Participants

In October 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning

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

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

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

Modifications to AEP's PJM Transmission Rates

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

FERC Transmission Complaint - AEP's SPP Participants

In June 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. 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 calendar year financial activity and projected plant balances. In December 2017, the FERC accepted the proposed modifications effective January 1, 2018, subject to refund, and set this matter for hearing and settlement procedures. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could total approximately $550 million, excluding AFUDC. As of June 30, 2018, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of June 30, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $624 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 June 30, 2018, (b) is subject to review by the LPSC and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. See "2017 Louisiana Formula Rate Filing" and "2018 Louisiana Formula Rate Filing" disclosures above.

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

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. As part of the reorganization, the bankruptcy court approved Westinghouse's sale of its nuclear business to Brookfield WEC Holdings (Brookfield), a nonaffiliated third party. Pursuant to the sale, Brookfield will assume all of I&M's contracts with Westinghouse. The sale is subject to regulatory approvals by the IURC and the MPSC 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 would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. The court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. Plaintiffs voluntarily dismissed the surviving claims with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether the trial court erred in dismissing plaintiffs' claims for breach of contract and breach of the implied covenant of good faith and fair dealing.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court's decisions in part. In June 2017, on rehearing, the court of appeals issued an amended opinion reversing the district court's dismissal of certain of plaintiffs' claims for breach of contract, vacating the denial of the plaintiffs' motion for partial summary judgment and remanding the case to the district court for further proceedings. The amended opinion and judgment affirmed the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removed the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. Responsive and supplemental filings have been made by all parties. The motion is fully briefed and remains pending before the court. 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.

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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 June 30, 2018, the AEP System had a total generating capacity of approximately 25,600 MWs, of which approximately 13,500 MWs were coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP’s investment to meet these existing and proposed requirements ranges from approximately $650 million to $1.5 billion through 2025.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or revising certain existing requirements. The cost estimates will also change based on: (a) the states’ implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity, (g) the outcome of the pending motion to modify the NSR consent decree and (h) other factors. In addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and competitive plants.

The table below represents the plants or units of plants previously retired that have a remaining net book value. As of June 30, 2018, the net book value before cost of removal, including related materials and supplies inventory, of the plants/units listed below was $190 million. Management is seeking or will seek recovery of the remaining net book value of $190 million in future rate proceedings.

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

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

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

Proposed Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate an obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. The other parties to the consent decree opposed AEP's motion. The district court granted AEP's request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until June 2020.

In January 2018, AEP filed a supplemental motion proposing to install the SCR at Rockport Plant, Unit 2 and achieve the final SO_2 emission cap applicable to the plant under the consent decree by the end of 2020, before the expiration of the initial lease term. Since all required emission reductions would be achieved, no unit retirements or other compensating measures were offered to maintain the benefits of the current consent decree. Responsive filings were filed in February 2018 by parties opposing AEP's proposed modifications to the consent decree. AEP was directed to file a detailed statement of the specific relief requested to address the changed circumstances at Rockport Plant, Unit 2, 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. In December 2017, the Federal EPA published final designations for certain areas' compliance with the 2010 SO_2 NAAQS. Additional designations will be made in 2020. States may develop additional requirements for AEP's facilities as a result of these designations. In June 2018, the Federal EPA proposed to retain the current primary standard for SO_2 of 75 parts per billion, without change.

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

Most areas of the country were designated attainment or unclassifiable for the 2015 ozone standard in November 2017. The Federal EPA finalized nonattainment designations for the remaining areas in April and July 2018. The Federal EPA has also issued information to assist the states in developing plans that address their obligations under the interstate transport provisions of the CAA for the 2008 and 2015 ozone standards. The Federal EPA has confirmed that for states included in the CSAPR program, there are no additional interstate transport obligations, as all areas of the country are expected to attain the 2008 ozone standard before 2023. State implementation plans for the 2015 ozone standard are due in October 2018. The Federal EPA had requested a stay of proceedings in the U.S. Court of Appeals for the District of Columbia Circuit where challenges to the 2015 ozone standard are pending, to allow reconsideration of that standard by the new administration. In June 2018, the court lifted the stay, allowing those challenges to proceed. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP's facilities based on the outcome of these activities.

Regional Haze

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

In March 2012, the Federal EPA proposed disapproval of a portion of the regional haze SIP in Arkansas. In April 2015, the Federal EPA published a proposed FIP to replace the disapproved portions, including revised BART determinations for the Flint Creek Plant that were consistent with the planned environmental controls to address other CAA requirements. In September 2016, the Federal EPA published a final FIP, retaining its BART determinations, but accelerating the schedule for implementation of certain required controls. The final rule is being challenged in the U.S. Court of Appeals for the Eighth Circuit, but has been held in abeyance to allow the parties to engage in settlement negotiations. Arkansas issued a proposed SIP revision to allow sources to participate in the CSAPR ozone season program in lieu of the source-specific NO_x BART requirements in the FIP, and the Federal EPA approved the revision. Arkansas issued a second proposal to revise the SO_2 BART determinations, and the public comment period on that action has closed. 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.

The Federal EPA also disapproved portions of the Texas regional haze SIP and promulgated a final FIP that did not include any BART determinations in January 2016. That rule was challenged in the U.S. Court of Appeals for the Fifth Circuit and in March 2017, the court granted partial remand of the final rule. In January 2017, the Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including Welsh Plant, Unit 1. In October 2017, the Federal EPA finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations as an alternative to source-specific SO_2 requirements. The 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. The Federal EPA confirmed in 2017 that changes to the CSAPR program, including the removal of Texas sources, did not alter that conclusion. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the Federal EPA rule that found that CSAPR provides greater visibility improvements than BART. Challenges to the changes made to the scope of the program in 2016 are being held in abeyance while the Federal EPA reconsiders the Texas SO_2 BART FIP.

CSAPR

In 2011, the Federal EPA issued CSAPR as a replacement for the 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 rule was vacated, but that decision was reversed on appeal to the U.S. Supreme Court. On remand, the U.S. Court of Appeals for the District of Columbia Circuit allowed Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. In July 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In October 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitions and other challenges to the rule. Management has been complying with the more stringent ozone season budgets while these petitions were pending.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

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

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

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. The Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal-fired and oil-fired units. Petitions for review of the Federal EPA's determination have been filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was scheduled for May 2017, but in April 2017, the Federal EPA requested that oral argument be postponed to facilitate its review of the rule, which remains in effect.

Climate Change, CO_2 Regulation and Energy Policy

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

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

In March 2017, the Federal EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of: (a) an Executive Order from the President of the United States titled "Promoting Energy Independence and Economic Growth" directing the Federal EPA to review the CPP and related rules, (b) the Federal EPA's initiation of a review of the CPP and (c) a forthcoming rulemaking related to the CPP consistent with the Executive Order, if the Federal EPA determines appropriate. In this same filing, the Federal EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review of any resulting rulemaking. The U.S. Court of Appeals for the District of Columbia Circuit granted the Federal EPA's motion in part and has requested periodic status reports. In October 2017, the Federal EPA issued a proposed rule repealing the CPP. In December 2017, the Federal EPA issued an advanced notice of proposed rulemaking seeking information that should be considered by the Federal EPA in developing revised guidelines for state programs. Management is actively monitoring these rulemakings and participating in the development of any new guidelines.

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. Management is taking steps to comply with these requirements, including increasing wind and solar installations, power purchases and broadening AEP System's portfolio of energy efficiency programs.

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

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force AEP to close some coal-fired facilities, which could possibly lead to impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four year implementation period. Certain records must be posted to a publicly available internet site. Initial groundwater monitoring reports were posted in the first quarter of 2018, and some of AEP's existing facilities were required to begin assessment monitoring programs to determine if unacceptable groundwater impacts will trigger future remedial actions.

In December 2016, the U.S. Congress passed legislation authorizing states to submit programs to regulate CCR facilities, and the Federal EPA to approve such programs if they are no less stringent than the minimum federal standards. The Federal EPA may also enforce compliance with the minimum standards until a state program is approved or if states fail to adopt their own programs. Oklahoma has received approval to operate its state program in lieu of the federal rules.

The final 2015 rule has been challenged in the courts. 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. A final rule was signed in July 2018 that modifies certain compliance deadlines and other requirements in the rule, including postponing the closure obligation for unlined surface impoundments that exceed a groundwater protection standard or fail to meet the minimum separation distance from the upper-most aquifer until October 2020, establishing numeric groundwater protection standards for four compounds that do not have primary drinking water standards, authorizing state and federal regulators to suspend groundwater monitoring requirements under limited circumstances and issue technical certifications. Additional changes to the minimum performance standards that were contained in the March proposed rule will be addressed in future rulemakings. Management supports the adoption of more flexible compliance alternatives subject to the Federal EPA or state oversight.

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

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Management recorded a $95 million increase in asset retirement obligations in 2015 based on the closure and post-closure care requirements in the final rule. This estimate does not include costs of groundwater remediation, if required. Management will continue to evaluate the rule’s impact on operations.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant’s cooling water intake screen (impingement) or entrained in the cooling water. Compliance timeframes are established by the permit agency through each facility’s National Pollutant Discharge Elimination System permit as those permits are renewed, and have been incorporated into permits at several AEP facilities. Petitions for review were filed by industry and environmental groups in the U.S. Court of Appeals for the Second Circuit. The court denied the petitions and upheld the final rule. AEP’s facilities are reviewing these requirements as their waste water discharge permits are renewed, and making appropriate adjustments to their intake structures.

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements will be implemented through each facility’s wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations filed a petition for reconsideration of the rule with the Federal EPA. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017. Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA’s recent actions on facilities’ wastewater discharge permitting. Management is actively participating in the reconsideration proceedings.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of “waters of the United States” in light of recent U.S. Supreme Court cases. The final rule was challenged in both courts of appeal and district courts. In January 2018, the U.S. Supreme Court ruled that challenges to the definition of “waters of the United States” must be filed in federal district courts. Challenges to the rule will proceed.

In March 2017, the Federal EPA published a notice of intent to review the rule and provide an advanced notice of a proposed rulemaking consistent with the Executive Order of the President of the United States directing the Federal

EPA and U.S. Army Corps of Engineers to review and rescind or revise the rule. In June 2017, the agencies signed a notice of proposed rule to rescind the definition of "waters of the United States" that was adopted in June 2015, and to re-codify the definition of that phrase as it existed immediately prior to that action. This action would effectively retain the status quo until a new rule is adopted by the agencies. A supplemental proposal was signed by the Administrator in June 2018 to provide further clarification of the impact of and support for repeal of the 2015 rule. The Federal EPA and U.S. Army Corps of Engineers also finalized a new rule to extend the applicability date of the 2015 rule to 2020. Challenges to the applicability date rule 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 are presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The following discussion of AEP's results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale and Amortization of Generation Deferrals as presented in the Registrants statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, they do not typically impact Operating Income or Earnings Attributable to AEP Common Shareholders. Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze AEP's financial performance in that it excludes the effect on Total Revenues caused by volatility in these expenses.

Operating Income, which is presented in accordance with GAAP in AEP’s statements of income, is the most directly comparable GAAP financial measure to the presentation of Gross Margin. AEP’s definition of Gross Margin may not be directly comparable to similarly titled financial measures used by other companies.

The following table presents Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Vertically Integrated Utilities	$276.8	$120.8	$508.0	$340.3
Transmission and Distribution Utilities	114.0	111.2	239.4	230.3
AEP Transmission Holdco	101.1	128.4	205.1	200.2
Generation & Marketing	38.8	26.4	57.0	212.6
Corporate and Other	(2.3)	(11.8)	(26.7)	(16.2)
Earnings Attributable to AEP Common Shareholders	$528.4	$375.0	$982.8	$967.2

AEP CONSOLIDATED

Second Quarter of 2018 Compared to Second Quarter of 2017

Earnings Attributable to AEP Common Shareholders increased from $375 million in 2017 to $528 million in 2018 primarily due to:

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

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Earnings Attributable to AEP Common Shareholders increased from $967 million in 2017 to $983 million in 2018 primarily due to:

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

These increases were partially offset by:

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

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions)			
Revenues	$2,349.0	$2,120.5	$4,757.0	$4,410.9
Fuel and Purchased Electricity	808.0	711.9	1,665.8	1,500.3
Gross Margin	1,541.0	1,408.6	3,091.2	2,910.6
Other Operation and Maintenance	703.8	717.1	1,443.8	1,377.2
Depreciation and Amortization	312.7	278.0	626.0	556.3
Taxes Other Than Income Taxes	107.7	99.4	217.6	200.5
Operating Income	416.8	314.1	803.8	776.6
Interest and Investment Income	2.4	1.0	5.0	4.1
Carrying Costs Income	2.3	5.1	5.1	9.2
Allowance for Equity Funds Used During Construction	7.3	6.3	14.7	12.5
Non-Service Cost Components of Net Periodic Benefit Cost	17.6	5.9	35.7	11.8
Interest Expense	(140.9)	(136.7)	(278.8)	(271.6)
Income Before Income Tax Expense and Equity Earnings (Loss)	305.5	195.7	585.5	542.6
Income Tax Expense	28.3	68.1	76.0	195.8
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.7	(6.2)	1.2	(4.9)
Net Income	277.9	121.4	510.7	341.9
Net Income Attributable to Noncontrolling Interests	1.1	0.6	2.7	1.6
Earnings Attributable to AEP Common Shareholders	$276.8	$120.8	$508.0	$340.3

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions of KWhs)			
Retail:				
Residential	7,545	6,499	17,117	14,738
Commercial	6,321	5,996	12,189	11,685
Industrial	8,942	8,689	17,439	16,953
Miscellaneous	586	562	1,139	1,098
Total Retail	23,394	21,746	47,884	44,474
Wholesale (a)	4,986	5,918	10,724	12,425
Total KWhs	28,380	27,664	58,608	56,899

(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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in degree days)			
Eastern Region				
Actual – Heating (a)	207	85	1,844	1,266
Normal – Heating (b)	138	138	1,740	1,753
Actual – Cooling (c)	480	335	486	336
Normal – Cooling (b)	328	324	333	329
Western Region				
Actual – Heating (a)	93	9	974	539
Normal – Heating (b)	32	33	907	925
Actual – Cooling (c)	901	637	937	719
Normal – Cooling (b)	692	696	719	720

(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.

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

Second Quarter of 2017	$120.8
Changes in Gross Margin:	
Retail Margins	112.8
Off-system Sales	(4.0)
Transmission Revenues	28.6
Other Revenues	(5.0)
Total Change in Gross Margin	132.4
Changes in Expenses and Other:	
Other Operation and Maintenance	13.3
Depreciation and Amortization	(34.7)
Taxes Other Than Income Taxes	(8.3)
Interest and Investment Income	1.4
Carrying Costs Income	(2.8)
Allowance for Equity Funds Used During Construction	1.0
Non-Service Cost Components of Net Periodic Pension Cost	11.7
Interest Expense	(4.2)
Total Change in Expenses and Other	(22.6)
Income Tax Expense	39.8
Equity Earnings (Loss) of Unconsolidated Subsidiaries	6.9
Net Income Attributable to Noncontrolling Interest	(0.5)
Second Quarter of 2018	$276.8

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

- Retail Margins increased $113 million primarily due to the following:
- A $90 million increase in weather-related usage across all regions.
- The effect of rate proceedings in AEP’s service territories which included:
- A $23 million increase from rate proceedings for I&M.
- An $18 million increase for SWEPCo primarily due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
- A $13 million increase for PSO due to new rates implemented in March 2018, inclusive of an $8 million decrease due to the change in the corporate federal tax rate.

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

- A $35 million increase for I&M in FERC generation wholesale municipal and cooperative revenues primarily due to changes to the annual formula rate.
- An $11 million increase in weather-normalized retail margins primarily in the residential and industrial classes.

These increases were partially offset by:

- A $47 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $10 million decrease due to lower weather-normalized wholesale margins, primarily due to SWEPCo and I&M wholesale customer load loss from contracts that expired at the end of 2017.

- A $9 million decrease primarily due to increased fuel and other variable production costs not recovered through fuel clauses or other trackers.
- Margins from Off-system Sales decreased $4 million primarily due to lower sales volumes.
- Transmission Revenues increased $29 million primarily due to the following:
- A $19 million increase primarily due to the annual formula rate true-up and decreased RTO provisions at I&M.
- A $10 million increase 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 was partially offset in Other Operation and Maintenance expense below.

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

- Other Operation and Maintenance expenses decreased $13 million primarily due to the following:
- A $63 million decrease in PJM transmission services.

This decrease was partially offset by:

- A $28 million increase in SPP transmission services.
- An $18 million increase due to the Wind Catcher Project for SWEPCo and PSO.
- Depreciation and Amortization expenses increased $35 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $8 million primarily due to:
- A $5 million increase in property taxes driven by an increase in utility plant.
- A $2 million increase in state and local taxes due to higher reported taxable KWh and taxable revenues.
- 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.
- Interest Expense increased $4 million primarily due to higher long-term debt balances at I&M.
- Income Tax Expense decreased $40 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT associated with certain depreciable property and by other book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.
- Equity Earnings (Loss) of Unconsolidated Subsidiaries increased $7 million primarily due to a prior period income tax adjustment recognized in 2017 for DHLC.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

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

Six Months Ended June 30, 2017	$340.3
Changes in Gross Margin:	
Retail Margins	162.4
Off-system Sales	(3.1)
Transmission Revenues	31.3
Other Revenues	(10.0)
Total Change in Gross Margin	180.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(66.6)
Depreciation and Amortization	(69.7)
Taxes Other Than Income Taxes	(17.1)
Interest and Investment Income	0.9
Carrying Costs Income	(4.1)
Allowance for Equity Funds Used During Construction	2.2
Non-Service Cost Components of Net Periodic Pension Cost	23.9
Interest Expense	(7.2)
Total Change in Expenses and Other	(137.7)
Income Tax Expense	119.8
Equity Earnings (Loss) of Unconsolidated Subsidiaries	6.1
Net Income Attributable to Noncontrolling Interest	(1.1)
Six Months Ended June 30, 2018	$508.0

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 $162 million primarily due to the following:
- A $179 million increase in weather-related usage across all regions.
- The effect of rate proceedings in AEP’s service territories which included:
- A $46 million increase from rate proceedings for I&M.
- A $39 million increase for SWEPCo due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
- A $17 million increase for PSO due to new rates implemented in March 2018, inclusive of a $10 million decrease due to the change in the corporate federal tax rate.

For the rate increases described above, $13 million relate to riders/trackers, which have corresponding increases in expense items below.

- A $31 million increase for I&M in FERC generation wholesale municipal and cooperative revenues primarily due to changes to the annual formula rate.
- A $28 million increase in weather-normalized retail margins primarily in the residential and industrial classes.

These increases were partially offset by:

- A $118 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $26 million decrease due to lower weather-normalized wholesale margins, primarily due to SWEPCo and I&M wholesale customer load loss from contracts that expired at the end of 2017.
- A $13 million decrease primarily due to increased fuel and other variable production costs not recovered through fuel clauses or other trackers.

- Margins from Off-system Sales decreased $3 million primarily due to lower sales volumes.
- Transmission Revenues increased $31 million primarily due to the following:
- An $18 million increase primarily due to the annual formula rate true-up and decreased RTO provisions at I&M.
- A $13 million increase primarily due to an increase in transmission investments in SPP.
- Other Revenues decreased $10 million primarily due to reduced rates for KPCo Demand Side Management programs beginning in 2018. This decrease was partially offset in Other Operation and Maintenance expense below.

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

- Other Operation and Maintenance expenses increased $67 million primarily due to the following:
- A $42 million increase in SPP transmission services.
- A $32 million increase due to the Wind Catcher Project for SWEPCo and PSO.
- A $16 million increase in plant maintenance primarily for KPCo and I&M.
- A $9 million increase due to an increase in estimated expense for claims related to asbestos exposure.

These increases were partially offset by:

- A $39 million decrease in PJM transmission services.
- A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2018.
- Depreciation and Amortization expenses increased $70 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $17 million primarily due to:
- An $8 million increase in property taxes driven by an increase in utility plant.
- A $6 million increase in state and local taxes due to higher reported taxable KWh and taxable revenues and a prior period refund.
- Non-Service Cost Components of Net Periodic Benefit Cost decreased $24 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.
- Interest Expense increased $7 million primarily due to increased long-term debt balances at I&M.
- Income Tax Expense decreased $120 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT associated with certain depreciable property and by other book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.
- Equity Earnings (Loss) of Unconsolidated Subsidiaries increased $6 million primarily due to a prior period income tax adjustment recognized in 2017 for DHLC.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions)			
Revenues	$1,137.0	$1,053.5	$2,299.4	$2,139.9
Purchased Electricity	196.7	186.9	441.3	410.3
Amortization of Generation Deferrals	56.4	53.3	115.0	114.2
Gross Margin	883.9	813.3	1,743.1	1,615.4
Other Operation and Maintenance	379.0	295.9	731.7	583.8
Depreciation and Amortization	184.4	163.9	357.0	320.1
Taxes Other Than Income Taxes	132.6	126.6	270.0	253.5
Operating Income	187.9	226.9	384.4	458.0
Interest and Investment Income (Loss)	(0.1)	0.9	1.3	4.4
Carrying Costs Income	0.6	0.6	1.3	2.5
Allowance for Equity Funds Used During Construction	7.2	1.2	15.2	5.4
Non-Service Cost Components of Net Periodic Benefit Cost	8.1	2.3	16.3	4.5
Interest Expense	(62.0)	(61.5)	(122.1)	(121.5)
Income Before Income Tax Expense	141.7	170.4	296.4	353.3
Income Tax Expense	27.7	59.2	57.0	123.0
Net Income	114.0	111.2	239.4	230.3
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$114.0	$111.2	$239.4	$230.3

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions of KWhs)			
Retail:				
Residential	6,409	5,956	13,206	11,850
Commercial	6,605	6,490	12,469	12,243
Industrial	6,025	5,941	11,539	11,417
Miscellaneous	175	171	328	331
Total Retail (a)	19,214	18,558	37,542	35,841
Wholesale (b)	534	761	1,201	1,559
Total KWhs	19,748	19,319	38,743	37,400

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in degree days)			
Eastern Region				
Actual – Heating (a)	274	97	2,158	1,500
Normal – Heating (b)	186	186	2,070	2,085
Actual – Cooling (c)	454	312	458	315
Normal – Cooling (b)	291	287	294	290
Western Region				
Actual – Heating (a)	4	1	234	103
Normal – Heating (b)	3	4	194	199
Actual – Cooling (d)	992	989	1,188	1,247
Normal – Cooling (b)	927	919	1,046	1,032

(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.

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

Second Quarter of 2017	$111.2
Changes in Gross Margin:	
Retail Margins	65.4
Off-system Sales	11.1
Transmission Revenues	(2.8)
Other Revenues	(3.1)
Total Change in Gross Margin	70.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(83.1)
Depreciation and Amortization	(20.5)
Taxes Other Than Income Taxes	(6.0)
Interest and Investment Income (Loss)	(1.0)
Allowance for Equity Funds Used During Construction	6.0
Non-Service Cost Components of Net Periodic Benefit Cost	5.8
Interest Expense	(0.5)
Total Change in Expenses and Other	(99.3)
Income Tax Expense	31.5
Second Quarter of 2018	$114.0

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 $65 million primarily due to the following:
- A $70 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance below.
- A $19 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.
- An $8 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in various expenses below.
- A $6 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
- A $4 million increase in Texas revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.

These increases were partially offset by:

- A $21 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- An $11 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 $6 million decrease in weather-normalized margins, primarily in the commercial and residential classes.

Margins from Off-system Sales increased $11 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 $3 million primarily due to the following:
- A $9 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.

This decrease was partially offset by:

- A $6 million increase due to recovery of increased transmission investment in ERCOT.
- Other Revenues decreased $3 million primarily due to securitization revenue in Texas related to Transition Funding. This decrease 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 $83 million primarily due to the following:
- A $105 million increase in recoverable transmission expenses that were fully recovered in rate recovery riders/trackers within Gross Margins above.
- A $19 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 $48 million decrease in Ohio PJM expenses related to the annual formula rate true-up that will be refunded in future periods.
- Depreciation and Amortization expenses increased $21 million primarily due to the following:
- An $11 million increase in depreciation expense due to an increase in the 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.
- Taxes Other Than Income Taxes increased $6 million primarily due to the following:
- A $3 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 KWhs. This increase was offset in Retail Margins above.
- Allowance for Equity Funds Used During Construction increased $6 million primarily due to the following:
- A $3 million increase due to increased transmission projects in Texas.
- A $1 million increase due to increased projects in Ohio.
- 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 $32 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 2017 Tax Reform legislation and a decrease in pretax book income.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

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

Six Months Ended June 30, 2017	$230.3
Changes in Gross Margin:	
Retail Margins	119.2
Off-system Sales	16.6
Transmission Revenues	(6.8)
Other Revenues	(1.3)
Total Change in Gross Margin	127.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(147.9)
Depreciation and Amortization	(36.9)
Taxes Other Than Income Taxes	(16.5)
Interest and Investment Income (Loss)	(3.1)
Carrying Costs Income	(1.2)
Allowance for Equity Funds Used During Construction	9.8
Non-Service Cost Components of Net Periodic Benefit Cost	11.8
Interest Expense	(0.6)
Total Change in Expenses and Other	(184.6)
Income Tax Expense	66.0
Six Months Ended June 30, 2018	$239.4

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 $119 million primarily due to the following:
  - A $109 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance below.
  - A $40 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 $14 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $12 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - An $11 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.
  - An $11 million increase in Texas weather-related usage primarily driven by a 127% increase in heating degree days partially offset by a 5% decrease in cooling degree days.

  These increases were partially offset by:
  - A $42 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.

- An $18 million decrease in Ohio due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.
- An $11 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues in Ohio. This decrease was partially offset by a decrease in Other Operation and Maintenance expenses below.
- A $9 million decrease in margin for the Ohio Phase-In-Recovery Rider including associated amortizations.

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- A $9 million decrease in Ohio revenues associated with smart grid riders. This decrease was partially offset by a decrease in various expenses below.
- Margins from Off-system Sales increased $17 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 $7 million primarily due to the following:
- A $20 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.

This decrease was partially offset by:

- A $13 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 $148 million primarily due to the following:
- A $149 million increase in recoverable transmission expenses that were fully recovered in rate recovery riders/trackers within Gross Margins above.
- A $40 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 $50 million decrease in Ohio PJM expenses related to the annual formula rate true-up that will be refunded in future periods.
- 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 $37 million primarily due to the following:
- An $18 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- A $12 million increase in recoverable DIR depreciation expense in Ohio. This increase was offset in Retail Margins above.
- A $4 million increase due to securitization amortizations related to Texas securitized transition funding. This increase was offset in Other Revenues and in Interest Expense.
- Taxes Other Than Income Taxes increased $17 million primarily due to the following:
- A $9 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- A $7 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 $10 million primarily due to the following:
- A $7 million increase due to increased transmission projects in Texas.
- A $1 million increase due to increased projects in Ohio.
- 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 $66 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 2017 Tax Reform legislation and a decrease in pretax book income.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions)			
Transmission Revenues	$212.5	$247.3	$418.0	$403.4
Other Operation and Maintenance	23.4	17.4	45.3	31.5
Depreciation and Amortization	33.8	24.0	65.6	48.6
Taxes Other Than Income Taxes	37.5	28.4	70.2	56.4
Operating Income	117.8	177.5	236.9	266.9
Interest and Investment Income	0.4	0.1	0.7	0.3
Allowance for Equity Funds Used During Construction	16.3	13.5	31.6	24.3
Non-Service Cost Components of Net Periodic Benefit Cost	0.7	—	1.4	0.1
Interest Expense	(21.5)	(17.1)	(42.6)	(34.4)
Income Before Income Tax Expense and Equity Earnings	113.7	174.0	228.0	257.2
Income Tax Expense	28.3	67.1	55.8	103.5
Equity Earnings of Unconsolidated Subsidiaries	16.5	22.1	34.5	48.1
Net Income	101.9	129.0	206.7	201.8
Net Income Attributable to Noncontrolling Interests	0.8	0.6	1.6	1.6
Earnings Attributable to AEP Common Shareholders	$101.1	$128.4	$205.1	$200.2

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	June 30, 2018	2017
	(in millions)	
Plant in Service	$6,158.5	$4,809.2
Construction Work in Progress	1,626.0	1,202.9
Accumulated Depreciation and Amortization	219.0	137.0
Total Transmission Property, Net	$7,565.5	$5,875.1

Second Quarter of 2018 Compared to Second Quarter of 2017

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

Second Quarter of 2017	$ 128.4
Changes in Transmission Revenues:	
Transmission Revenues	(34.8)
Total Change in Transmission Revenues	(34.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(6.0)
Depreciation and Amortization	(9.8)
Taxes Other Than Income Taxes	(9.1)
Interest and Investment Income	0.3
Allowance for Equity Funds Used During Construction	2.8
Non-Service Cost Components of Net Periodic Pension Cost	0.7
Interest Expense	(4.4)
Total Change in Expenses and Other	(25.5)
Income Tax Expense	38.8
Equity Earnings of Unconsolidated Subsidiaries	(5.6)
Net Income Attributable to Noncontrolling Interests	(0.2)
Second Quarter of 2018	$ 101.1

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

- Transmission Revenues decreased $35 million primarily due to the following:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates.

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

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

- Other Operation and Maintenance expenses increased $6 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $10 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $9 million primarily due to higher property taxes as a result of increased transmission investment.
- Interest Expense increased $4 million primarily due to higher outstanding long-term debt balances.
- Income Tax Expense decreased $39 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.

- Equity Earnings of Unconsolidated Subsidiaries decreased $6 million due to lower pretax equity earnings at ETT primarily due to decreased revenues driven by Tax Reform.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

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

Six Months Ended June 30, 2017	$200.2
Changes in Transmission Revenues:	
Transmission Revenues	14.6
Total Change in Transmission Revenues	14.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(13.8)
Depreciation and Amortization	(17.0)
Taxes Other Than Income Taxes	(13.8)
Interest and Investment Income	0.4
Allowance for Equity Funds Used During Construction	7.3
Non-Service Cost Components of Net Periodic Pension Cost	1.3
Interest Expense	(8.2)
Total Change in Expenses and Other	(43.8)
Income Tax Expense	47.7
Equity Earnings of Unconsolidated Subsidiaries	(13.6)
Six Months Ended June 30, 2018	$205.1

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

- Transmission Revenues increased $15 million primarily due to the following:
- A $79 million increase in revenues due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform. The decrease in Transmission Revenues related to Tax Reform is offset by a decrease in Income Tax Expense below.

This increase was partially offset by:

- A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates.

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

- Other Operation and Maintenance expenses increased $14 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $17 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $14 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $7 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $8 million primarily due to higher outstanding long-term debt balances.
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Income Tax Expense decreased $48 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and a decrease in pretax book income.

- Equity Earnings of Unconsolidated Subsidiaries decreased $14 million primarily due to lower pretax equity earnings at ETT due to decreased revenues driven by Tax Reform and an ETT rate reduction implemented in March 2017.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions)			
Revenues	$460.7	$410.6	$965.8	$1,002.0
Fuel, Purchased Electricity and Other	354.0	302.9	762.8	708.1
Gross Margin	106.7	107.7	203.0	293.9
Other Operation and Maintenance	56.8	72.7	124.4	172.5
Gain on Sale of Merchant Generation Assets	—	0.1	—	(226.4)
Depreciation and Amortization	7.5	5.6	14.4	11.3
Taxes Other Than Income Taxes	3.4	3.7	6.6	5.7
Operating Income	39.0	25.6	57.6	330.8
Interest and Investment Income	3.8	3.0	6.3	5.2
Non-Service Cost Components of Net Periodic Benefit Cost	3.8	2.2	7.7	4.5
Interest Expense	(4.0)	(4.2)	(7.9)	(10.7)
Income Before Income Tax Expense and Equity Earnings	42.6	26.6	63.7	329.8
Income Tax Expense	4.3	0.2	7.3	117.2
Equity Earnings of Unconsolidated Subsidiaries	0.3	—	0.3	—
Net Income	38.6	26.4	56.7	212.6
Net Loss Attributable to Noncontrolling Interests	(0.2)	—	(0.3)	—
Earnings Attributable to AEP Common Shareholders	$38.8	$26.4	$57.0	$212.6

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
	(in millions of MWhs)			
Fuel Type:				
Coal	4	2	6	8
Natural Gas	—	—	—	2
Total MWhs	4	2	6	10

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

Second Quarter of 2017	$26.4
Changes in Gross Margin:	
Generation	(14.0)
Retail, Trading and Marketing	11.0
Other Revenues	2.0
Total Change in Gross Margin	(1.0)
Changes in Expenses and Other:	
Other Operation and Maintenance	15.9
Gain on Sale of Merchant Generation Assets	0.1
Depreciation and Amortization	(1.9)
Taxes Other Than Income Taxes	0.3
Interest and Investment Income	0.8
Non-Service Cost Components of Net Periodic Benefit Cost	1.6
Interest Expense	0.2
Total Change in Expenses and Other	17.0
Income Tax Expense	(4.1)
Equity Earnings of Unconsolidated Subsidiaries	0.3
Net Loss Attributable to Noncontrolling Interests	0.2
Second Quarter of 2018	$38.8

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

- Generation decreased $14 million primarily due to decreased hedge gains in 2018.
- Retail, Trading and Marketing increased $11 million due to higher mark-to-market hedge gains.

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

- Other Operation and Maintenance expenses decreased $16 million due to the retirement of the Stuart plant in 2018.
- Income Tax Expense increased $4 million primarily due to an increase in pretax book income, which is offset by the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform.

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

Six Months Ended June 30, 2017	$212.6
Changes in Gross Margin:	
Generation	(67.1)
Retail, Trading and Marketing	(26.8)
Other Revenues	3.0
Total Change in Gross Margin	(90.9)
Changes in Expenses and Other:	
Other Operation and Maintenance	48.1
Gain on Sale of Merchant Generation Assets	(226.4)
Depreciation and Amortization	(3.1)
Taxes Other Than Income Taxes	(0.9)
Interest and Investment Income	1.1
Non-Service Cost Components of Net Periodic Benefit Cost	3.2
Interest Expense	2.8
Total Change in Expenses and Other	(175.2)
Income Tax Expense	109.9
Equity Earnings of Unconsolidated Subsidiaries	0.3
Net Loss Attributable to Noncontrolling Interests	0.3
Six Months Ended June 30, 2018	$57.0

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

- Generation decreased $67 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets in 2017.
- Retail, Trading and Marketing decreased $27 million primarily due to lower margins in 2018 combined with the impact of favorable wholesale trading and marketing performance in 2017.
- Other Revenues increased $3 million primarily due to renewable projects placed in service.

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

- Other Operation and Maintenance expenses decreased $48 million primarily due to the sale of certain merchant generation assets in 2017.
- Gain on Sale of Merchant Generation Assets decreased $226 million due to the sale of certain merchant generation assets in 2017.
- Income Tax Expense decreased $110 million primarily due to a decrease in pretax book income driven by the gain on the sale of certain merchant generation assets in 2017 and the change in the corporate federal income tax rate from

35% in 2017 to 21% in 2018 as a result of Tax Reform.

CORPORATE AND OTHER

Second Quarter of 2018 Compared to Second Quarter of 2017

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $12 million in 2017 to a loss of $2 million in 2018 primarily due to an $18 million decrease in income tax expense related to the enactment of the Kentucky state tax legislation in the second quarter of 2018 and an $11 million decrease in general corporate expenses, partially offset by a $16 million increase in interest expense as a result of increased debt outstanding.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $16 million in 2017 to a loss of $26 million in 2018 primarily due to a $28 million increase in interest expense as a result of increased debt outstanding and a $20 million impairment of an equity investment and related assets, partially offset by a $12 million decrease in general corporate expenses and an $18 million decrease in income tax expense related to the enactment of the Kentucky state tax legislation in the second quarter of 2018.

AEP SYSTEM INCOME TAXES

Second Quarter of 2018 Compared to Second Quarter of 2017

Income Tax Expense decreased $118 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 2017 Tax Reform legislation and amortization of Excess ADIT.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Income Tax Expense decreased $360 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 2017 Tax Reform legislation, amortization of Excess ADIT and a decrease in pretax book income.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	June 30, 2018		December 31, 2017	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$22,032.0	50.8 %	$21,173.3	51.5 %
Short-term Debt	2,589.2	6.0	1,638.6	4.0
Total Debt	24,621.2	56.8	22,811.9	55.5
AEP Common Equity	18,722.3	43.1	18,287.0	44.4
Noncontrolling Interests	29.1	0.1	26.6	0.1
Total Debt and Equity Capitalization	$43,372.6	100.0%	$41,125.5	100.0%

AEP's ratio of debt-to-total capital increased from 55.5% as of December 31, 2017 to 56.8% as of June 30, 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 June 30, 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 June 30, 2018, available liquidity was approximately $1.4 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	211.2	
Total Liquidity Sources	3,211.2	
Less: AEP Commercial Paper Outstanding	1,814.0	
Net Available Liquidity	$1,397.2	

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 six months of 2018 was $2.3 billion. The weighted-average interest rate for AEP's commercial paper during 2018 was 2.22%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $305 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2018 was $80 million with maturities ranging from August 2018 to June 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 June 30, 2018, this contractually-defined percentage was 55%. Nonperformance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facility does not permit the lenders to refuse a draw if a material adverse change occurs.

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

Dividend Policy and Restrictions

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

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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.

	Six Months Ended June 30, 2018	2017
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$412.6	$403.5
Net Cash Flows from Operating Activities	2,006.8	1,717.0
Net Cash Flows Used for Investing Activities	(3,238.9)	(396.8)
Net Cash Flows from (Used for) Financing Activities	1,206.8	(1,379.4)
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(25.3)	(59.2)
Cash, Cash Equivalents and Restricted Cash at End of Period	$387.3	$344.3

Operating Activities

	Six Months Ended June 30, 2018	2017
	(in millions)	
Net Income	$986.8	$970.4
Non-Cash Adjustments to Net Income (a)	1,232.5	1,194.5
Mark-to-Market of Risk Management Contracts	(112.9)	(84.7)
Pension Contributions to Qualified Plant Trust	—	(93.3)
Property Taxes	119.9	122.9
Deferred Fuel Over/Under Recovery, Net	12.3	20.7
Recovery of Ohio Capacity Costs, Net	35.8	47.1
Provision for Refund - Global Settlement, Net	(5.5)	(88.1)
Change in Other Noncurrent Assets	10.4	(188.0)
Change in Other Noncurrent Liabilities	185.1	132.0
Change in Certain Components of Working Capital	(457.6)	(316.5)
Net Cash Flows from Operating Activities	$2,006.8	$1,717.0

(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 increased by $290 million primarily due to the following:

- A $198 million increase in cash from Change in Other Noncurrent Assets primarily due to changes in regulatory assets as a result of the impact of the FERC settlement on regulated AEP subsidiaries with rider recovery mechanisms.
- A $93 million increase in cash due to a pension contribution made in the second quarter of 2017.
- An $83 million increase in cash due to Provision for Refund - Global Settlement, Net. Refunds were primarily issued in 2017.
-

- A $54 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for additional information.
- A $53 million increase in Change in Other Noncurrent Liabilities primarily due to increased Accumulated Provisions for Rate Refunds as a result of Tax Reform.

These increases in cash were partially offset by:

- A $141 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 and increased usage of fuel, materials and supplies.

Investing Activities

	Six Months Ended June 30,	
	2018	2017
	(in millions)	
Construction Expenditures	$(3,223.4)	$(2,510.4)
Acquisitions of Nuclear Fuel	(24.2)	(38.9)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6
Other	8.7	(7.1)
Net Cash Flows Used for Investing Activities	$(3,238.9)	$(396.8)

Net Cash Flows Used for Investing Activities increased by $2.8 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 $713 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $505 million and AEP Transmission Holdco of $124 million.

Financing Activities

	Six Months Ended June 30,	
	2018	2017
	(in millions)	
Issuance of Common Stock, Net	$50.9	$—
Issuance/Retirement of Debt, Net	1,820.0	(710.6)
Dividends Paid on Common Stock	(614.2)	(584.9)
Other	(49.9)	(83.9)
Net Cash Flows from (Used for) Financing Activities	$1,206.8	$(1,379.4)

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

- A $1.2 billion increase in cash due to increased issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- An $812 million increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 12 - Financing Activities for additional information.
- A $560 million increase in cash due to decreased retirements of long-term debt. See Note 12 - Financing Activities for additional information.
- A $51 million increase in cash due to increased proceeds from issuances of common stock.

These increases in cash were partially offset by:

- A $29 million decrease due to increased common stock dividend payments primarily due to increased dividends per share from 2017 to 2018.

In July 2018, AEP Texas retired $78 million of Securitization Bonds.

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

In July 2018, OPCo retired $24 million of Securitization Bonds.

BUDGETED CONSTRUCTION EXPENDITURES

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

OFF-BALANCE SHEET ARRANGEMENTS

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

	June 30, 2018	December 31, 2017
	(in millions)	
Rockport Plant, Unit 2 Future Minimum Lease Payments	$ 664.7	$ 738.4
Railcars Maximum Potential Loss from Lease Agreement	13.9	17.9

For complete information on each of these off-balance sheet arrangements, see the “Off-Balance Sheet Arrangements” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2017 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

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

CYBER SECURITY

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

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

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

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

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

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

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2017 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting pronouncements.

ACCOUNTING PRONOUNCEMENTS

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

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

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

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2017:
MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2018

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2017	$42.1	$ (131.3)	$ 163.9	$74.7
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(30.0)	(2.7)	(12.9)	(45.6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	11.3	11.3
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	(0.5)	(0.5)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	102.2	48.4	—	150.6
Total MTM Risk Management Contract Net Assets (Liabilities) as of June 30, 2018	$114.3	$ (85.6)	$ 161.8	190.5
Commodity Cash Flow Hedge Contracts				(33.8)
Fair Value Hedge Contracts				(27.9)
Collateral Deposits				(3.3)
Total MTM Derivative Contract Net Assets as of June 30, 2018				$125.5

(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 June 30, 2018, credit exposure net of collateral to sub investment grade counterparties was approximately 6.4%, 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 June 30, 2018, the following table approximates AEP’s counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$516.5	$ 1.5	$ 515.0	3	$ 279.5
Noninvestment Grade	0.5	0.5	—	—	—
No External Ratings:					
Internal Investment Grade	126.5	—	126.5	3	76.2
Internal Noninvestment Grade	54.2	10.5	43.7	2	29.3
Total as of June 30, 2018	$697.7	$ 12.5	$ 685.2		

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 June 30, 2018, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

Six Months Ended June 30, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$0.1	$1.8	$ 0.3	$0.1	$0.2	$0.5	$ 0.2	$0.1

VaR Model
Non-Trading Portfolio

Six Months Ended June 30, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$2.6	$7.3	$ 3.1	$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 six months ended June 30, 2018 and 2017, a 100 basis point change in the benchmark rate on AEP’s variable rate debt would impact pretax interest expense annually by $25 million and $27 million, respectively.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
REVENUES				
Vertically Integrated Utilities	$2,340.7	$ 2,095.7	$4,722.2	$ 4,365.5
Transmission and Distribution Utilities	1,127.9	1,026.6	2,269.1	2,093.0
Generation & Marketing	435.3	386.5	912.8	945.3
Other Revenues	109.3	67.7	157.4	106.0
TOTAL REVENUES	4,013.2	3,576.5	8,061.5	7,509.8
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	566.9	522.3	1,068.7	1,157.9
Purchased Electricity for Resale	776.7	669.2	1,767.0	1,438.8
Other Operation	780.3	616.4	1,506.7	1,240.1
Maintenance	295.9	290.1	594.4	593.6
Gain on Sale of Merchant Generation Assets	—	0.1	—	(226.4)
Depreciation and Amortization	553.2	485.5	1,092.9	967.4
Taxes Other Than Income Taxes	283.2	259.6	568.8	519.4
TOTAL EXPENSES	3,256.2	2,843.2	6,598.5	5,690.8
OPERATING INCOME	757.0	733.3	1,463.0	1,819.0
Other Income (Expense):				
Interest and Investment Income	3.8	2.3	5.9	10.3
Carrying Costs Income	2.9	5.7	6.3	11.6
Allowance for Equity Funds Used During Construction	30.8	21.0	61.5	42.2
Non-Service Cost Components of Net Periodic Benefit Cost	31.4	11.4	63.4	22.8
Interest Expense	(242.3)	(222.9)	(476.3)	(444.7)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	583.6	550.8	1,123.8	1,461.2
Income Tax Expense	72.2	190.6	174.2	533.8
Equity Earnings of Unconsolidated Subsidiaries	18.7	16.0	37.2	43.0
NET INCOME	530.1	376.2	986.8	970.4
Net Income Attributable to Noncontrolling Interests	1.7	1.2	4.0	3.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$528.4	$ 375.0	$982.8	$ 967.2
	492,688,344	491,790,752	492,479,035	491,751,614

WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING				
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.07	$ 0.76	$ 2.00	$ 1.97
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	493,505,08[illegible]	492,642,100	493,317,35[illegible]	492,337,255
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.07	$ 0.76	$ 1.99	$ 1.96
CASH DIVIDENDS DECLARED PER SHARE	$ 0.62	$ 0.59	$ 1.24	$ 1.18

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net Income	$530.1	$376.2	$986.8	$970.4
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.5 and $4.6 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $1.2 and $(4.1) for the Six Months Ended June 30, 2018 and 2017, Respectively	1.8	8.5	4.5	(7.6)
Securities Available for Sale, Net of Tax of $0 and $0.4 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $0 and $1.0 for the Six Months Ended June 30, 2018 and 2017, Respectively	—	0.6	—	1.8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.3) and $0.2 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(0.7) and $0.3 for the Six Months Ended June 30, 2018 and 2017, Respectively	(1.2)	0.3	(2.6)	0.5
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	0.6	9.4	1.9	(5.3)
TOTAL COMPREHENSIVE INCOME	530.7	385.6	988.7	965.1
Total Comprehensive Income Attributable to Noncontrolling Interests	1.7	1.2	4.0	3.2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$529.0	$384.4	$984.7	$961.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2018 and 2017
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Paid-in Capital	Retained Earnings			
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				(583.2)		(1.7)	(584.9)
Other Changes in Equity			48.4			0.8	49.2
Net Income				967.2		3.2	970.4
Other Comprehensive Loss					(5.3)		(5.3)
TOTAL EQUITY – JUNE 30, 2017	512.0	$3,328.3	$6,381.0	$8,276.4	$ (161.6)	$ 25.4	$17,849.5
TOTAL EQUITY – DECEMBER 31, 2017	512.2	$3,329.4	$6,398.7	$8,626.7	$ (67.8)	$ 26.6	$18,313.6
Issuance of Common Stock	0.9	6.0	44.9				50.9
Common Stock Dividends				(612.3)		(1.9)	(614.2)
Other Changes in Equity			15.0			0.4	15.4
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				982.8		4.0	986.8
Other Comprehensive Income					1.9		1.9
TOTAL EQUITY – JUNE 30, 2018	513.1	$3,335.4	$6,458.6	$9,023.1	$ (94.8)	$ 29.1	$18,751.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$211.2	$ 214.6
Restricted Cash (June 30, 2018 and December 31, 2017 Amounts Include $176.1 and $198, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding)	176.1	198.0
Other Temporary Investments (June 30, 2018 and December 31, 2017 Amounts Include $157.1 and $155.4, Respectively, Related to EIS and Transource Energy)	163.1	161.7
Accounts Receivable:		
Customers	827.2	643.9
Accrued Unbilled Revenues	207.4	230.2
Pledged Accounts Receivable – AEP Credit	1,133.4	954.2
Miscellaneous	143.3	101.2
Allowance for Uncollectible Accounts	(40.6)	(38.5)
Total Accounts Receivable	2,270.7	1,891.0
Fuel	352.8	387.7
Materials and Supplies	562.8	565.5
Risk Management Assets	194.6	126.2
Regulatory Asset for Under-Recovered Fuel Costs	280.4	292.5
Margin Deposits	115.3	105.5
Prepayments and Other Current Assets	243.1	310.4
TOTAL CURRENT ASSETS	4,570.1	4,253.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	21,235.2	20,760.5
Transmission	19,818.7	18,972.5
Distribution	20,447.9	19,868.5
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	3,880.8	3,706.3
Construction Work in Progress	4,630.3	4,120.7
Total Property, Plant and Equipment	70,012.9	67,428.5
Accumulated Depreciation and Amortization	17,571.4	17,167.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	52,441.5	50,261.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,375.6	3,587.6
Securitized Assets	1,082.1	1,211.2
Spent Nuclear Fuel and Decommissioning Trusts	2,554.9	2,527.6
Goodwill	52.5	52.5
Long-term Risk Management Assets	264.5	282.1

Deferred Charges and Other Noncurrent Assets	2,528.9	2,553.5
TOTAL OTHER NONCURRENT ASSETS	9,858.5	10,214.5
TOTAL ASSETS	$66,870.1	$ 64,729.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable	$1,635.4	$ 2,065.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	718.0
Other Short-term Debt	1,839.2	920.6
Total Short-term Debt	2,589.2	1,638.6
Long-term Debt Due Within One Year (June 30, 2018 and December 31, 2017 Amounts Include $423.2 and $406.9, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,281.4	1,753.7
Risk Management Liabilities	54.0	61.6
Customer Deposits	369.0	357.0
Accrued Taxes	943.9	1,115.5
Accrued Interest	235.2	234.5
Regulatory Liability for Over-Recovered Fuel Costs	11.4	11.9
Other Current Liabilities	938.8	1,033.2
TOTAL CURRENT LIABILITIES	9,058.3	8,271.3
NONCURRENT LIABILITIES		
Long-term Debt (June 30, 2018 and December 31, 2017 Amounts Include $1,247.3 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)	19,750.6	19,419.6
Long-term Risk Management Liabilities	279.6	322.0
Deferred Income Taxes	7,085.3	6,813.9
Regulatory Liabilities and Deferred Investment Tax Credits	8,683.7	8,422.3
Asset Retirement Obligations	1,966.2	1,925.5
Employee Benefits and Pension Obligations	329.4	398.1
Deferred Credits and Other Noncurrent Liabilities	871.6	830.9
TOTAL NONCURRENT LIABILITIES	38,966.4	38,132.3
TOTAL LIABILITIES	48,024.7	46,403.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	70.4	—
Contingently Redeemable Performance Share Awards	23.6	11.9
TOTAL MEZZANINE EQUITY	94.0	11.9

EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2018	2017		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	513,130,857	512,210,644		
(20,204,160 and 20,205,046 Shares were Held in Treasury as of June 30, 2018 and December 31, 2017, Respectively)			3,335.4	3,329.4
Paid-in Capital			6,458.6	6,398.7
Retained Earnings			9,023.1	8,626.7
Accumulated Other Comprehensive Income (Loss)			(94.8)	(67.8)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			18,722.3	18,287.0
Noncontrolling Interests			29.1	26.6
TOTAL EQUITY			18,751.4	18,313.6
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$ 66,870.1	$ 64,729.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$ 986.8	$ 970.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,092.9	967.4
Deferred Income Taxes	149.7	424.1
Allowance for Equity Funds Used During Construction	(61.5)	(42.2)
Mark-to-Market of Risk Management Contracts	(112.9)	(84.7)
Amortization of Nuclear Fuel	51.4	71.6
Pension Contributions to Qualified Plan Trust	—	(93.3)
Property Taxes	119.9	122.9
Deferred Fuel Over/Under-Recovery, Net	12.3	20.7
Gain on Sale of Merchant Generation Assets	—	(226.4)
Recovery of Ohio Capacity Costs	35.8	47.1
Provision for Refund – Global Settlement, Net	(5.5)	(88.1)
Change in Other Noncurrent Assets	10.4	(188.0)
Change in Other Noncurrent Liabilities	185.1	132.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(209.9)	270.5
Fuel, Materials and Supplies	31.2	(9.5)
Accounts Payable	(53.6)	(170.5)
Accrued Taxes, Net	(127.8)	(72.8)
Other Current Assets	14.8	(45.3)
Other Current Liabilities	(112.3)	(288.9)
Net Cash Flows from Operating Activities	2,006.8	1,717.0
INVESTING ACTIVITIES		

Construction Expenditures	(3,223.4)	(2,510.4)
Purchases of Investment Securities	(1,069.2)	(1,318.2)
Sales of Investment Securities	1,037.8	1,289.1
Acquisitions of Nuclear Fuel	(24.2)	(38.9)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6
Other Investing Activities	40.1	22.0
Net Cash Flows Used for Investing Activities	(3,238.9)	(396.8)
FINANCING ACTIVITIES		
Issuance of Common Stock	50.9	—
Issuance of Long-term Debt	2,209.2	1,050.0
Commercial Paper and Credit Facility Borrowings	205.6	—
Change in Short-term Debt, Net	952.0	138.7
Retirement of Long-term Debt	(1,339.8)	(1,899.3)
Commercial Paper and Credit Facility Repayments	(207.0)	—
Make Whole Premium on Extinguishment of Long-term Debt	—	(44.9)
Principal Payments for Capital Lease Obligations	(33.5)	(33.3)
Dividends Paid on Common Stock	(614.2)	(584.9)
Other Financing Activities	(16.4)	(5.7)
Net Cash Flows from (Used for) Financing Activities	1,206.8	(1,379.4)
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(25.3)	(59.2)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	412.6	403.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 387.3	$ 344.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 455.4	$ 442.3
Net Cash Paid (Received) for Income Taxes	33.8	(21.2)
Noncash Acquisitions Under Capital Leases	32.8	23.6
	940.0	597.9

Construction Expenditures Included in Current Liabilities as of June 30,		
Construction Expenditures Included in Noncurrent Liabilities as of June 30,	—	71.8
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	0.6	26.0
Noncash Contribution of Assets by Noncontrolling Interest	84.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0.7	2.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

AEP TEXAS INC.
AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	3,122	3,095	5,786	5,296
Commercial	2,954	2,935	5,266	5,260
Industrial	2,229	2,251	4,189	4,158
Miscellaneous	149	144	271	272
Total Retail	8,454	8,425	15,512	14,986

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	4	1	234	103
Normal – Heating (b)	3	4	194	199
Actual – Cooling (c)	992	989	1,188	1,247
Normal – Cooling (b)	927	919	1,046	1,032

(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.

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

Second Quarter of 2017	$49.0
Changes in Gross Margin:	
Retail Margins	1.9
Off-system Sales	(0.1)
Transmission Revenues	(0.4)
Other Revenues	(2.5)
Total Change in Gross Margin	(1.1)
Changes in Expenses and Other:	
Other Operation and Maintenance	(14.2)
Depreciation and Amortization	(5.4)
Taxes Other Than Income Taxes	(1.9)
Other Income	2.4
Non-Service Cost Components of Net Periodic Benefit Cost	2.1
Interest Expense	(1.3)
Total Change in Expenses and Other	(18.3)
Income Tax Expense	16.9
Second Quarter of 2018	$46.5

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

- Retail Margins increased $2 million primarily due to the following:
  - A $6 million increase in revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $4 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.

  These increases were partially offset by:
  - A $7 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- Transmission Revenues were unchanged primarily due to the following:
  - A $6 million increase due to recovery of increased transmission investment in ERCOT.

  This increase was offset by:
  - A $6 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.
- Other Revenues decreased $3 million primarily due to securitization revenue related to Transition Funding. This decrease 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 $14 million primarily due to the following:
  - A $5 million increase in distribution expenses primarily due to advanced metering infrastructure projects.

- A $4 million increase in ERCOT transmission expenses. This increase was offset by an increase in Retail Margins above.
- A $4 million increase in employee-related expenses.

- Depreciation and Amortization expenses increased $5 million primarily due to the following:
  - A $4 million increase in depreciation expense primarily due to an increase in the depreciable base of transmission and distribution assets.
  - A $2 million increase in amortization related to advanced metering infrastructure projects.

  These increases were partially offset by:
  - A $1 million decrease in securitization amortizations related to Transition Funding. This decrease was offset in Other Revenues above and in Interest Expense below.
- Other Income increased $2 million primarily due to a $3 million increase in AFUDC due to increased transmission projects.
- Interest Expense increased $1 million primarily due to the following:
  - A $6 million increase due to the issuance of long-term debt in September 2017.

  This increase was offset by:
  - A $4 million decrease due to a higher debt component of AFUDC from increased transmission projects.
  - A $2 million decrease in securitization assets related to Transition Funding. This decrease was offset above in Other Revenues and in Depreciation and Amortization.
- 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 amortization of Excess ADIT associated with certain depreciable property and a decrease in pretax book income.

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

Six Months Ended June 30, 2017	$82.3
Changes in Gross Margin:	
Retail Margins	20.5
Off-system Sales	(1.7)
Transmission Revenues	2.0
Other Revenues	0.2
Total Change in Gross Margin	21.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(25.5)
Depreciation and Amortization	(12.6)
Taxes Other Than Income Taxes	(6.0)
Other Income	5.6
Non-Service Cost Components of Net Periodic Benefit Cost	4.3
Interest Expense	(1.3)
Total Change in Expenses and Other	(35.5)
Income Tax Expense	25.5
Six Months Ended June 30, 2018	$93.3

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 $21 million primarily due to the following:
  - A $12 million increase in revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - An $11 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.
  - An $11 million increase in weather-related usage primarily driven by a 127% increase in heating degree days partially offset by a 5% decrease in cooling degree days.

  These increases were partially offset by:
  - A $12 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- Transmission Revenues increased by $2 million primarily due to the following:
  - A $13 million increase due to recovery of increased transmission investment in ERCOT.

  This increase was partially offset by:
  - An $11 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $26 million primarily due to the following:

- A $15 million increase in ERCOT transmission expenses. This increase was partially offset by an increase in Retail Margins above.
- A $6 million increase in distribution expenses primarily due to advanced metering infrastructure projects.
- A $3 million increase in employee-related expenses.

- Depreciation and Amortization expenses increased $13 million primarily due to the following:
  - A $7 million increase in depreciation expense primarily due to an increase in the depreciable base of transmission and distribution assets.
  - A $4 million increase in securitization amortizations related to Transition Funding. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $2 million increase in amortization primarily due to advanced metering infrastructure projects and capitalized software.
- Taxes Other Than Income Taxes increased $6 million primarily due to increased property taxes as a result of additional capital investment and increased tax rates.
- Other Income increased $6 million primarily due to a $7 million increase in AFUDC due to increased transmission projects.
- Non-Service Cost Components of Net Periodic Cost decreased $4 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 Texas' ability to capitalize a portion of its non-service cost components.
- Interest Expense increased $1 million primarily due to the following:
  - An $11 million increase due to the issuance of long-term debt in September 2017.

  This increase was partially offset by:
  - A $6 million decrease due to a higher debt component of AFUDC from increased transmission projects.
  - A $5 million decrease in securitization assets related to Transition Funding. This decrease was offset above in Other Revenues and in Depreciation and Amortization.
- 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 amortization of Excess ADIT associated with certain depreciable property and a decrease in pretax book income.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
REVENUES				
Electric Transmission and Distribution	$370.1	$371.0	$722.5	$699.9
Sales to AEP Affiliates	17.6	17.8	35.8	31.9
Other Revenues	0.6	0.7	1.6	1.3
TOTAL REVENUES	388.3	389.5	759.9	733.1
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	5.8	5.9	14.7	8.9
Other Operation	118.0	106.5	235.0	215.3
Maintenance	23.1	20.4	44.6	38.8
Depreciation and Amortization	121.6	116.2	231.6	219.0
Taxes Other Than Income Taxes	33.6	31.7	66.0	60.0
TOTAL EXPENSES	302.1	280.7	591.9	542.0
OPERATING INCOME	86.2	108.8	168.0	191.1
Other Income (Expense):				
Other Income	2.9	0.5	8.9	3.3
Non-Service Cost Components of Net Periodic Benefit Cost	3.0	0.9	6.1	1.8
Interest Expense	(36.6)	(35.3)	(71.6)	(70.3)
INCOME BEFORE INCOME TAX EXPENSE	55.5	74.9	111.4	125.9
Income Tax Expense	9.0	25.9	18.1	43.6
NET INCOME	$46.5	$49.0	$93.3	$82.3

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
Net Income	$46.5	$49.0	$93.3	$82.3
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0.1 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $0.1 and $0.2 for the Six Months Ended June 30, 2018 and 2017, Respectively	0.3	0.3	0.5	0.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0.1 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $0 and $0.1 for the Six Months Ended June 30, 2018 and 2017, Respectively	—	—	0.1	0.1
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3	0.6	0.6
TOTAL COMPREHENSIVE INCOME	$46.8	$49.3	$93.9	$82.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER’S EQUITY – DECEMBER 31, 2016	$857.9	$814.1	$ (14.9)	$1,657.1
Capital Contribution from Parent	200.0			200.0
Net Income		82.3		82.3
Other Comprehensive Income			0.6	0.6
TOTAL COMMON SHAREHOLDER’S EQUITY – JUNE 30, 2017	$1,057.9	$896.4	$ (14.3)	$1,940.0
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		93.3		93.3
Other Comprehensive Income			0.6	0.6
TOTAL COMMON SHAREHOLDER’S EQUITY – JUNE 30, 2018	$1,157.9	$1,219.7	$ (14.7)	$2,362.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$0.1	$2.0
Restricted Cash for Securitized Transition Funding	131.9	155.2
Advances to Affiliates	27.1	111.9
Accounts Receivable:		
Customers	138.9	105.3
Affiliated Companies	42.7	12.3
Accrued Unbilled Revenues	79.7	75.8
Miscellaneous	0.3	1.3
Allowance for Uncollectible Accounts	(0.5)	(0.7)
Total Accounts Receivable	261.1	194.0
Fuel	4.6	3.6
Materials and Supplies	50.5	52.0
Risk Management Assets	0.4	0.5
Accrued Tax Benefits	16.0	41.0
Prepayments and Other Current Assets	3.6	3.6
TOTAL CURRENT ASSETS	495.3	563.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	351.1	350.7
Transmission	3,263.3	3,053.6
Distribution	3,913.8	3,718.6
Other Property, Plant and Equipment	488.9	461.0
Construction Work in Progress	1,009.1	835.7
Total Property, Plant and Equipment	9,026.2	8,419.6
Accumulated Depreciation and Amortization	1,627.8	1,594.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,398.4	6,825.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	399.3	378.7
Securitized Transition Assets (June 30, 2018 and December 31, 2017 Amounts Include $769 and $869.5, Respectively, Related to Transition Funding)	786.6	891.2
Long-term Risk Management Assets	0.1	—
Deferred Charges and Other Noncurrent Assets	115.5	114.8
TOTAL OTHER NONCURRENT ASSETS	1,301.5	1,384.7
TOTAL ASSETS	$9,195.2	$8,773.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable:		
General	$220.1	$379.4
Affiliated Companies	23.0	30.2
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2018 and December 31, 2017 Amounts Include $243.7 and $236.1, Respectively, Related to Transition Funding)	293.7	266.1
Accrued Taxes	89.7	77.2
Accrued Interest (June 30, 2018 and December 31, 2017 Amounts Include $13.4 and $15.9, Respectively, Related to Transition Funding)	41.5	42.2
Other Current Liabilities	81.6	76.4
TOTAL CURRENT LIABILITIES	749.6	871.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2018 and December 31, 2017 Amounts Include $658.9 and $790.1, Respectively, Related to Transition Funding)	3,697.6	3,383.2
Deferred Income Taxes	908.1	913.1
Regulatory Liabilities and Deferred Investment Tax Credits	1,336.1	1,320.5
Oklaunion Purchase Power Agreement	51.7	52.0
Deferred Credits and Other Noncurrent Liabilities	89.2	63.4
TOTAL NONCURRENT LIABILITIES	6,082.7	5,732.2
TOTAL LIABILITIES	6,832.3	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	1,219.7	1,124.6
Accumulated Other Comprehensive Income (Loss)	(14.7)	(12.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,362.9	2,169.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$9,195.2	$8,773.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30,	
	2018	2017
OPERATING ACTIVITIES		
Net Income	$93.3	$82.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	231.6	219.0
Deferred Income Taxes	24.9	71.8
Allowance for Equity Funds Used During Construction	(9.4)	(2.2)
Mark-to-Market of Risk Management Contracts	—	0.3
Pension Contributions to Qualified Plan Trust	—	(8.8)
Property Taxes	(38.4)	(32.7)
Change in Other Noncurrent Assets	(36.1)	(20.4)
Change in Other Noncurrent Liabilities	21.6	5.9
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(67.1)	(38.0)
Fuel, Materials and Supplies	0.5	4.8
Accounts Payable	(29.6)	(4.5)
Accrued Taxes, Net	37.5	(4.3)
Other Current Assets	1.6	1.4
Other Current Liabilities	(5.5)	(31.0)
Net Cash Flows from Operating Activities	224.9	243.6
INVESTING ACTIVITIES		
Construction Expenditures	(792.8)	(378.5)
Change in Advances to Affiliates, Net	84.8	0.3
Other Investing Activities	19.2	6.9
Net Cash Flows Used for Investing Activities	(688.8)	(371.3)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100.0	200.0
Issuance of Long-term Debt – Nonaffiliated	494.5	—
Change in Advances from Affiliates, Net	—	28.2
Retirement of Long-term Debt – Nonaffiliated	(154.1)	(117.1)
Principal Payments for Capital Lease Obligations	(2.3)	(1.9)
Other Financing Activities	0.6	0.8
Net Cash Flows from Financing Activities	438.7	110.0
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding	(25.2)	(17.7)
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	$132.0	$129.2

SUPPLEMENTARY INFORMATION

Cash Paid for Interest, Net of Capitalized Amounts	$69.3	$69.4
Net Cash Paid (Received) for Income Taxes	(22.4)	1.5
Noncash Acquisitions Under Capital Leases	6.3	2.9
Construction Expenditures Included in Current Liabilities as of June 30,	186.8	95.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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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 June 30,	
	2018	2017
	(in millions)	
Plant In Service	$ 5,840.5	$ 4,493.3
Construction Work in Progress	1,585.9	1,197.0
Accumulated Depreciation and Amortization	210.5	133.1
Total Transmission Property, Net	$ 7,215.9	$ 5,557.2

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

Second Quarter of 2017	$ 107.4
Changes in Transmission Revenues:	
Transmission Revenues	(45.6)
Total Change in Transmission Revenues	(45.6)
Changes in Expenses and Other:	
Other Operation and Maintenance	(7.1)
Depreciation and Amortization	(9.6)
Taxes Other Than Income Taxes	(9.0)
Interest Income	0.3
Allowance for Equity Funds Used During Construction	2.9
Interest Expense	(4.6)
Total Change in Expenses and Other	(27.1)
Income Tax Expense	35.8
Second Quarter of 2018	$ 70.5

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

- Transmission Revenues decreased $46 million primarily due to the following:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates.
  - An $18 million decrease in revenues primarily due to an out of period correction of an error related to revenue recorded from 2013 through March 31, 2018. The out of period correction relates to certain transmission assets that management believes should not have been included in the SPP transmission formula rate.

  These decreases were partially offset by:

- A $37 million increase in revenues due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform. The decrease in Transmission Revenues related to Tax Reform is offset by a decrease in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $7 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $10 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $9 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $3 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $5 million primarily due to higher outstanding long-term debt balances.
- 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.

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

Six Months Ended June 30, 2017	$ 164.4
Changes in Transmission Revenues:	
Transmission Revenues	(4.8)
Total Change in Transmission Revenues	(4.8)
Changes in Expenses and Other:	
Other Operation and Maintenance	(14.1)
Depreciation and Amortization	(16.9)
Taxes Other Than Income Taxes	(13.3)
Interest Income	0.5
Allowance for Equity Funds Used During Construction	7.3
Interest Expense	(8.5)
Total Change in Expenses and Other	(45.0)
Income Tax Expense	41.8
Six Months Ended June 30, 2018	$ 156.4

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

- Transmission Revenues decreased $5 million primarily due to the following:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates.
  - An $18 million decrease in revenues primarily due to an out of period correction of an error related to revenue recorded from 2013 through March 31, 2018. The out of period correction relates to certain transmission assets that management believes should not have been included in the SPP transmission formula rate.

  These decreases were partially offset by:
  - A $79 million increase in revenues due to an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform. The decrease in Transmission Revenues related to Tax Reform is offset by a decrease in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $14 million primarily due to increased transmission investment.
- Depreciation and Amortization expenses increased $17 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $13 million primarily due to higher property taxes as a result of increased transmission investment.
- Allowance for Equity Funds Used During Construction increased $7 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- Interest Expense increased $9 million primarily due to higher outstanding long-term debt balances.

- Income Tax Expense decreased $42 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 COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
REVENUES				
Transmission Revenues	$51.2	$44.0	$82.5	$63.2
Sales to AEP Affiliates	132.6	185.4	294.7	318.8
Other Revenues	—	—	0.1	0.1
TOTAL REVENUES	183.8	229.4	377.3	382.1
EXPENSES				
Other Operation	18.5	11.3	35.1	20.4
Maintenance	2.2	2.3	4.8	5.4
Depreciation and Amortization	32.4	22.8	63.0	46.1
Taxes Other Than Income Taxes	36.6	27.6	67.7	54.4
TOTAL EXPENSES	89.7	64.0	170.6	126.3
OPERATING INCOME	94.1	165.4	206.7	255.8
Other Income (Expense):				
Interest Income	0.4	0.1	0.8	0.3
Allowance for Equity Funds Used During Construction	16.3	13.4	31.6	24.3
Interest Expense	(20.3)	(15.7)	(40.2)	(31.7)
INCOME BEFORE INCOME TAX EXPENSE	90.5	163.2	198.9	248.7
Income Tax Expense	20.0	55.8	42.5	84.3
NET INCOME	$70.5	$107.4	$156.4	$164.4

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 137.

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

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	$1,455.0	$ 502.6	$1,957.6
Capital Contributions from Member	166.7		166.7
Net Income		164.4	164.4
TOTAL MEMBER'S EQUITY – JUNE 30, 2017	$1,621.7	$ 667.0	$2,288.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	$1,816.6	$ 788.7	$2,605.3
Capital Contributions from Member	377.0		377.0
Net Income		156.4	156.4
TOTAL MEMBER'S EQUITY – JUNE 30, 2018	$2,193.6	$ 945.1	$3,138.7

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Advances to Affiliates	$53.6	$ 146.3
Accounts Receivable:		
Customers	15.3	19.1
Affiliated Companies	88.8	93.2
Miscellaneous	1.1	1.3
Total Accounts Receivable	105.2	113.6
Materials and Supplies	16.0	13.6
Accrued Tax Benefits	32.9	46.6
Prepayments and Other Current Assets	12.4	7.6
TOTAL CURRENT ASSETS	220.1	327.7
TRANSMISSION PROPERTY		
Transmission Property	5,700.0	5,336.1
Other Property, Plant and Equipment	140.5	131.4
Construction Work in Progress	1,585.9	1,312.7
Total Transmission Property	7,426.4	6,780.2
Accumulated Depreciation and Amortization	210.5	170.4
TOTAL TRANSMISSION PROPERTY – NET	7,215.9	6,609.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	18.2	11.7
Deferred Property Taxes	73.1	117.8
Deferred Charges and Other Noncurrent Assets	7.4	1.1
TOTAL OTHER NONCURRENT ASSETS	98.7	130.6
TOTAL ASSETS	$7,534.7	$ 7,068.1

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 167.5	$ 15.7
Accounts Payable:		
General	230.3	473.2
Affiliated Companies	66.8	52.9
Long-term Debt Due Within One Year – Nonaffiliated	50.0	50.0
Accrued Taxes	181.8	225.4
Accrued Interest	11.7	15.0
Other Current Liabilities	7.0	4.1
TOTAL CURRENT LIABILITIES	715.1	836.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,500.9	2,500.4
Deferred Income Taxes	659.0	601.7
Regulatory Liabilities	501.6	493.7
Deferred Credits and Other Noncurrent Liabilities	19.4	30.7
TOTAL NONCURRENT LIABILITIES	3,680.9	3,626.5
TOTAL LIABILITIES	4,396.0	4,462.8
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	2,193.6	1,816.6
Retained Earnings	945.1	788.7
TOTAL MEMBER'S EQUITY	3,138.7	2,605.3
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 7,534.7	$ 7,068.1

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 137.

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

	Six Months Ended June 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$156.4	$164.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	63.0	46.1
Deferred Income Taxes	50.2	134.0
Allowance for Equity Funds Used During Construction	(31.6)	(24.3)
Property Taxes	44.7	44.1
Long-term Accounts Receivable – Affiliated	(6.2)	(27.6)
Change in Other Noncurrent Assets	(7.0)	(8.8)
Change in Other Noncurrent Liabilities	17.8	17.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8.4	(37.0)
Materials and Supplies	(2.4)	(5.9)
Accounts Payable	13.7	(2.7)
Accrued Taxes, Net	(29.8)	(27.1)
Accrued Interest	(3.3)	(0.7)
Other Current Assets	0.4	(4.7)
Other Current Liabilities	(28.2)	1.0
Net Cash Flows from Operating Activities	246.1	267.8
INVESTING ACTIVITIES		
Construction Expenditures	(855.4)	(721.2)
Change in Advances to Affiliates, Net	92.7	44.9
Acquisitions of Assets	(13.1)	—
Other Investing Activities	1.1	(0.5)
Net Cash Flows Used for Investing Activities	(774.7)	(676.8)
FINANCING ACTIVITIES		
Capital Contributions from Member	377.0	166.7
Change in Advances from Affiliates, Net	151.8	243.3
Other Financing Activities	(0.2)	(1.0)
Net Cash Flows from Financing Activities	528.6	409.0
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$—	$—
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$42.7	$31.4
Net Cash Paid (Received) for Income Taxes	(20.4)	(67.0)
Construction Expenditures Included in Current Liabilities as of June 30,	234.7	190.3

See Condensed Notes to Condensed Consolidated Financial Statements beginning on page 137.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	2,388	2,091	6,233	5,341
Commercial	1,581	1,541	3,275	3,132
Industrial	2,361	2,376	4,738	4,675
Miscellaneous	205	201	429	411
Total Retail	6,535	6,209	14,675	13,559
Wholesale	614	884	1,109	1,690
Total KWhs	7,149	7,093	15,784	15,249

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	129	45	1,518	1,000
Normal – Heating (b)	91	90	1,408	1,418
Actual – Cooling (c)	537	373	545	375
Normal – Cooling (b)	363	360	370	367

(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.

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

Second Quarter of 2017	$52.1
Changes in Gross Margin:	
Retail Margins	(12.0)
Off-system Sales	0.6
Transmission Revenues	2.2
Other Revenues	(1.2)
Total Change in Gross Margin	(10.4)
Changes in Expenses and Other:	
Other Operation and Maintenance	24.4
Depreciation and Amortization	(4.6)
Taxes Other Than Income Taxes	(2.9)
Interest Income	0.1
Carrying Costs Income	0.2
Allowance for Equity Funds Used During Construction	0.9
Non-Service Cost Components of Net Periodic Benefit Cost	3.1
Interest Expense	0.4
Total Change in Expenses and Other	21.6
Income Tax Expense	14.1
Second Quarter of 2018	$77.4

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

- Retail Margins decreased $12 million primarily due to the following:
- A $26 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $10 million decrease in weather-normalized margins occurring across all retail classes.
- A $6 million increase in deferred fuel related to recoverable PJM expenses that were offset below.

These decreases were partially offset by:

- A $26 million increase in weather-related usage primarily due to a 44% increase in cooling degree days.
- A $3 million increase primarily due to increases from rate riders in Virginia. This increase is partially offset by an increase in Other Operation and Maintenance expenses.

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

- Other Operation and Maintenance expenses decreased $24 million primarily due to the following:
  - A $36 million decrease in PJM expenses related to the annual formula rate true-up that will be refunded in future periods.

  This decrease was partially offset by:
  - A $9 million increase in recoverable PJM expenses. This increase was offset in Retail Margins above.
  - A $5 million increase in storm-related expenses.
- Depreciation and Amortization expenses increased $5 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $3 million primarily driven by an increase in property taxes due to additional investments in utility plant.
- 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 APCo’s ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $14 million primarily due to the change in 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.

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

Six Months Ended June 30, 2017	$162.7
Changes in Gross Margin:	
Retail Margins	3.0
Off-system Sales	0.3
Transmission Revenues	0.4
Other Revenues	(3.4)
Total Change in Gross Margin	0.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(0.7)
Depreciation and Amortization	(12.5)
Taxes Other Than Income Taxes	(6.5)
Interest Income	0.1
Carrying Costs Income	0.4
Allowance for Equity Funds Used During Construction	2.0
Non-Service Cost Components of Net Periodic Benefit Cost	6.3
Interest Expense	1.1
Total Change in Expenses and Other	(9.8)
Income Tax Expense	49.7
Six Months Ended June 30, 2018	$202.9

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 $75 million increase in weather-related usage primarily driven by a 52% increase in heating degree days along with a 45% increase in cooling degree days.
  - A $5 million increase primarily due to increases from rate riders in Virginia. This was partially offset by an increase in Other Operation and Maintenance expenses.

  These increases were partially offset by:
  - A $58 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $15 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $5 million decrease in weather-normalized margins occurring across all retail classes.

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

- Other Operation and Maintenance expenses increased $1 million primarily due to the following:
- A $21 million increase in recoverable PJM expenses. This increase in expense was primarily offset within Retail Margins above.
- A $7 million increase in storm-related expenses.
- A $5 million increase in estimated expenses for claims related to asbestos exposure.
- A $5 million increase in employee-related expenses.

These increases were partially offset by:

- A $37 million decrease in PJM expenses related to the annual formula rate true-up that will be refunded in future periods.
- Depreciation and Amortization expenses increased $13 million primarily due to a higher depreciable base.
- Taxes Other Than Income Taxes increased $7 million primarily driven by an increase in property taxes due to additional investments in utility plant.
- 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 APCo’s ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $50 million primarily due to the change in corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT associated with certain depreciable property and a decrease in pretax book income.

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$618.8	$625.6	$1,386.3	$1,370.6
Sales to AEP Affiliates	46.4	46.3	95.8	88.7
Other Revenues	1.8	3.4	5.3	8.8
TOTAL REVENUES	667.0	675.3	1,487.4	1,468.1
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	155.3	152.5	224.3	319.7
Purchased Electricity for Resale	64.5	65.2	270.4	156.0
Other Operation	109.9	139.2	248.1	253.1
Maintenance	65.7	60.8	137.7	132.0
Depreciation and Amortization	105.3	100.7	213.8	201.3
Taxes Other Than Income Taxes	33.7	30.8	67.5	61.0
TOTAL EXPENSES	534.4	549.2	1,161.8	1,123.1
OPERATING INCOME	132.6	126.1	325.6	345.0
Other Income (Expense):				
Interest Income	0.6	0.5	0.9	0.8
Carrying Costs Income	0.5	0.3	1.0	0.6
Allowance for Equity Funds Used During Construction	2.9	2.0	5.5	3.5
Non-Service Cost Components of Net Periodic Benefit Cost	4.4	1.3	8.9	2.6
Interest Expense	(47.8)	(48.2)	(95.2)	(96.3)
INCOME BEFORE INCOME TAX EXPENSE	93.2	82.0	246.7	256.2
Income Tax Expense	15.8	29.9	43.8	93.5
NET INCOME	$77.4	$52.1	$202.9	$162.7

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

See Condensed Notes to

Condensed Financial Statements of Registrants beginning on page 137.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net Income	$77.4	$52.1	$202.9	$162.7
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $(0.1) for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(0.1) and $(0.2) for the Six Months Ended June 30, 2018 and 2017, Respectively	(0.2)	(0.2)	(0.4)	(0.4)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.1) for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(0.4) and $(0.3) for the Six Months Ended June 30, 2018 and 2017, Respectively	(0.8)	(0.3)	(1.6)	(0.6)
TOTAL OTHER COMPREHENSIVE LOSS	(1.0)	(0.5)	(2.0)	(1.0)
TOTAL COMPREHENSIVE INCOME	$76.4	$51.6	$200.9	$161.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 260.4	$ 1,828.7	$ 1,502.8	$ (8.4)	$ 3,583.5
Common Stock Dividends			(60.0)		(60.0)
Net Income			162.7		162.7
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2017	$ 260.4	$ 1,828.7	$ 1,605.5	$ (9.4)	$ 3,685.2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 260.4	$ 1,828.7	$ 1,714.1	$ 1.3	$ 3,804.5
Common Stock Dividends			(80.0)		(80.0)
ASU 2018-02 Adoption			0.1	0.3	0.4
Net Income			202.9		202.9
Other Comprehensive Loss				(2.0)	(2.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	$ 260.4	$ 1,828.7	$ 1,837.1	$ (0.4)	$ 3,925.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$2.8	$ 2.9
Restricted Cash for Securitized Funding	17.7	16.3
Advances to Affiliates	23.4	23.5
Accounts Receivable:		
Customers	177.9	123.1
Affiliated Companies	80.1	69.3
Accrued Unbilled Revenues	53.4	74.1
Miscellaneous	1.0	1.1
Allowance for Uncollectible Accounts	(3.9)	(3.7)
Total Accounts Receivable	308.5	263.9
Fuel	69.4	89.3
Materials and Supplies	99.2	99.5
Risk Management Assets	60.4	24.9
Regulatory Asset for Under-Recovered Fuel Costs	162.6	88.8
Margin Deposits	12.4	14.4
Prepayments and Other Current Assets	8.5	12.7
TOTAL CURRENT ASSETS	764.9	636.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,477.7	6,446.9
Transmission	3,082.9	3,019.9
Distribution	3,843.8	3,763.8
Other Property, Plant and Equipment	450.8	427.9
Construction Work in Progress	602.1	483.0
Total Property, Plant and Equipment	14,457.3	14,141.5
Accumulated Depreciation and Amortization	4,028.8	3,896.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,428.5	10,245.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	527.4	573.9
Securitized Assets	270.4	282.3
Long-term Risk Management Assets	2.1	1.1
Deferred Charges and Other Noncurrent Assets	211.0	190.0
TOTAL OTHER NONCURRENT ASSETS	1,010.9	1,047.3
TOTAL ASSETS	$12,204.3	$ 11,928.6

See
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Notes to

Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$172.7	$ 186.0
Accounts Payable:		
General	227.7	264.9
Affiliated Companies	81.4	92.7
Long-term Debt Due Within One Year – Nonaffiliated	530.5	249.2
Risk Management Liabilities	1.4	1.3
Customer Deposits	88.0	86.1
Accrued Taxes	94.0	94.5
Accrued Interest	41.1	40.5
Other Current Liabilities	89.9	109.0
TOTAL CURRENT LIABILITIES	1,326.7	1,124.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,543.2	3,730.9
Long-term Risk Management Liabilities	0.5	0.2
Deferred Income Taxes	1,593.2	1,565.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,522.3	1,454.9
Asset Retirement Obligations	105.5	100.2
Employee Benefits and Pension Obligations	66.2	73.3
Deferred Credits and Other Noncurrent Liabilities	120.9	74.7
TOTAL NONCURRENT LIABILITIES	6,951.8	6,999.9
TOTAL LIABILITIES	8,278.5	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	1,837.1	1,714.1
Accumulated Other Comprehensive Income (Loss)	(0.4)	1.3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,925.8	3,804.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$12,204.3	$ 11,928.6

See
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Condensed Financial Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
OPERATING ACTIVITIES		
Net Income	$202.9	$162.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	213.8	201.3
Deferred Income Taxes	10.8	86.2
Allowance for Equity Funds Used During Construction	(5.5)	(3.5)
Mark-to-Market of Risk Management Contracts	(36.1)	(39.4)
Pension Contributions to Qualified Plan Trust	—	(10.2)
Deferred Fuel Over/Under-Recovery, Net	(73.8)	(4.0)
Change in Other Noncurrent Assets	32.0	15.5
Change in Other Noncurrent Liabilities	68.7	13.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	4.7	24.0
Fuel, Materials and Supplies	20.2	0.3
Accounts Payable	(11.1)	18.7
Accrued Taxes, Net	(7.6)	(35.8)
Other Current Assets	7.1	8.5
Other Current Liabilities	(21.9)	(14.1)
Net Cash Flows from Operating Activities	404.2	423.9
INVESTING ACTIVITIES		
Construction Expenditures	(406.8)	(372.2)
Change in Advances to Affiliates, Net	0.1	0.3
Other Investing Activities	7.8	10.5
Net Cash Flows Used for Investing Activities	(398.9)	(361.4)
FINANCING ACTIVITIES		
Issuance of Long-term Debt - Nonaffiliated	103.7	320.9
Change in Advances from Affiliates, Net	(13.3)	45.1
Retirement of Long-term Debt - Nonaffiliated	(11.7)	(365.9)
Principal Payments for Capital Lease Obligations	(3.4)	(3.5)
Dividends Paid on Common Stock	(80.0)	(60.0)
Other Financing Activities	0.7	0.4
Net Cash Flows Used for Financing Activities	(4.0)	(63.0)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	1.3	(0.5)
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	$20.5	$18.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$90.9	$92.4

Net Cash Paid for Income Taxes	19.7	32.0
Noncash Acquisitions Under Capital Leases	2.7	1.7
Construction Expenditures Included in Current Liabilities as of June 30,	89.5	99.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	1,245	1,119	2,868	2,611
Commercial	1,209	1,170	2,385	2,327
Industrial	1,973	1,919	3,877	3,815
Miscellaneous	15	14	35	34
Total Retail	4,442	4,222	9,165	8,787
Wholesale	2,388	2,806	5,314	5,760
Total KWhs	6,830	7,028	14,479	14,547

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	364	168	2,521	1,816
Normal – Heating (b)	235	234	2,403	2,419
Actual – Cooling (c)	362	260	362	260
Normal – Cooling (b)	261	259	263	261

(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.

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

Second Quarter of 2017	$ 10.5
Changes in Gross Margin:	
Retail Margins	59.7
Off-system Sales	(2.0)
Transmission Revenues	18.7
Other Revenues	1.0
Total Change in Gross Margin	77.4
Changes in Expenses and Other:	
Other Operation and Maintenance	22.6
Depreciation and Amortization	(12.8)
Taxes Other Than Income Taxes	(3.4)
Interest Income	0.7
Carrying Cost Income	(2.7)
Allowance for Equity Funds Used During Construction	(0.2)
Non-Service Cost Components of Net Periodic Benefit Cost	2.9
Interest Expense	(3.6)
Total Change in Expenses and Other	3.5
Income Tax Expense	3.3
Second Quarter of 2018	$ 94.7

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

- Retail Margins increased $60 million primarily due to the following:
- A $35 million increase in FERC generation wholesale municipal and cooperative revenues primarily due to the annual formula rate true-up and changes to the formula rate.
- A $23 million increase from rate proceedings in the I&M service territory. The increase in Retail Margins relating to riders had corresponding increases in other expense items below.
- A $16 million increase in weather-related usage primarily due to a 117% increase in heating degree days and a 40% increase in cooling degree days.

These increases were partially offset by:

- An $11 million decrease related to over/under recovery of riders.
- Transmission Revenues increased $19 million increase primarily due to the annual formula rate true-up and decreased RTO provisions.

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

- Other Operation and Maintenance expenses decreased $23 million primarily due to a $26 million decrease in transmission expenses driven by a decrease in recoverable PJM expenses. This decrease was partially offset within Retail Margins above.

- Depreciation and Amortization expenses increased $13 million primarily due to a higher depreciable base and increased depreciation rates approved in the 2017 Michigan base rate case.
- Taxes Other Than Income Taxes increased $3 million primarily due to increased property and payroll taxes.

- Carrying Cost Income decreased $3 million primarily due to a decrease in carrying charges for certain riders in Indiana. This decrease was partially offset in Interest Expense below.
- 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.
- Interest Expense increased $4 million primarily due to increased long-term debt balances. This increase was partially offset in Carrying Cost Income above.
- Income Tax Expense decreased $3 million primarily due to other book/tax differences which are accounted for on a flow-through basis and 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.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Reconciliation of Six Months Ended June 30, 2017 to Six Months
Ended June 30, 2018
Net Income
(in millions)

Six Months Ended June 30, 2017	$78.9
Changes in Gross Margin:	
Retail Margins	62.9
Off-system Sales	(1.6)
Transmission Revenues	21.5
Other Revenues	(1.7)
Total Change in Gross Margin	81.1
Changes in Expenses and Other:	
Other Operation and Maintenance	10.5
Depreciation and Amortization	(22.1)
Taxes Other Than Income Taxes	(5.5)
Interest Income	(0.2)
Carrying Cost Income	(3.7)
Allowance for Equity Funds Used During Construction	(0.5)
Non-Service Cost Components of Net Periodic Benefit Cost	5.9
Interest Expense	(5.6)
Total Change in Expenses and Other	(21.2)
Income Tax Expense	20.1
Six Months Ended June 30, 2018	$158.9

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 $63 million primarily due to the following:
- A $46 million increase from rate proceedings in the I&M service territory. The increase in Retail Margins relating to riders had corresponding increases in other expense items below.
- A $31 million increase in FERC generation wholesale municipal and cooperative revenues primarily due to the annual formula rate true-up and changes to the formula rate.
- A $30 million increase in weather-related usage primarily due to a 39% increase in heating degree days and a 40% increase in cooling degree days.
- A $3 million increase due to lower weather-normalized margins primarily due to wholesale customer load loss from contracts that expired at the end of 2017.

These increases were partially offset by:

- A $15 million decrease related to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- A $15 million decrease related to over/under recovery of riders.
- A $3 million decrease due to increased fuel and other variable production costs not recovered through fuel clauses or other trackers.
-

Transmission Revenues increased $22 million increase primarily due to the annual formula rate true-up and decreased RTO provisions.

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

- Other Operation and Maintenance expenses decreased $11 million primarily due to the following:
- A $14 million decrease in transmission expenses primarily due to a decrease in recoverable PJM expenses. This decrease was partially offset within Retail Margins above.
- A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2018.

These decreases were partially offset by:

- A $4 million increase in employee-related expenses.
- A $4 million increase in Cook Plant refueling outage amortization expense, primarily due to increased costs of outages.
- Depreciation and Amortization expenses increased $22 million primarily due to a higher depreciable base and increased depreciation rates approved in the 2017 Michigan base rate case.
- Taxes Other Than Income Taxes increased $6 million primarily due to increased property and payroll taxes.
- Carrying Cost Income decreased $4 million primarily due to a decrease in carrying charges for certain riders in Indiana. This decrease was partially offset in Interest Expense below.
- 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 I&M’s ability to capitalize a portion of its non-service cost components.
- Interest Expense increased $6 million primarily due to increased long-term debt balances. This increase was partially offset in Carrying Cost Income above.
- Income Tax Expense decreased $20 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.

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$560.1	$451.9	$1,114.0	$990.4
Other Revenues – Affiliated	27.2	12.4	45.1	31.1
Other Revenues – Nonaffiliated	2.4	3.0	7.4	6.3
TOTAL REVENUES	589.7	467.3	1,166.5	1,027.8
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	73.4	71.1	150.9	161.8
Purchased Electricity for Resale	63.2	31.0	118.8	68.3
Purchased Electricity from AEP Affiliates	60.4	49.9	121.8	103.8
Other Operation	130.4	159.7	276.5	296.8
Maintenance	57.4	50.7	111.9	102.1
Depreciation and Amortization	62.6	49.8	121.9	99.8
Taxes Other Than Income Taxes	24.9	21.5	49.9	44.4
TOTAL EXPENSES	472.3	433.7	951.7	877.0
OPERATING INCOME	117.4	33.6	214.8	150.8
Other Income (Expense):				
Interest Income	1.0	0.3	1.2	1.4
Carrying Costs Income	1.6	4.3	4.0	7.7
Allowance for Equity Funds Used During Construction	2.3	2.5	4.1	4.6
Non-Service Cost Components of Net Periodic Benefit Cost	4.5	1.6	9.0	3.1
Interest Expense	(31.4)	(27.8)	(61.1)	(55.5)
INCOME BEFORE INCOME TAX EXPENSE	95.4	14.5	172.0	112.1
Income Tax Expense	0.7	4.0	13.1	33.2
NET INCOME	$94.7	$10.5	$158.9	$78.9

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
Net Income	$94.7	$10.5	$158.9	$78.9
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.2 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $0.2 and $0.4 for the Six Months Ended June 30, 2018 and 2017, Respectively	0.5	0.4	0.9	0.7
TOTAL COMPREHENSIVE INCOME	$95.2	$10.9	$159.8	$79.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 56.6	$ 980.9	$ 1,130.5	$ (16.2)	$ 2,151.8
Common Stock Dividends			(62.5)		(62.5)
Net Income			78.9		78.9
Other Comprehensive Income				0.7	0.7
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2017	$ 56.6	$ 980.9	$ 1,146.9	$ (15.5)	$ 2,168.9
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 56.6	$ 980.9	$ 1,192.2	$ (12.1)	$ 2,217.6
Common Stock Dividends			(67.0)		(67.0)
ASU 2018-02 Adoption			0.3	(2.7)	(2.4)
Net Income			158.9		158.9
Other Comprehensive Income				0.9	0.9
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	$ 56.6	$ 980.9	$ 1,284.4	$ (13.9)	$ 2,308.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.4	$ 1.3
Advances to Affiliates	92.3	12.4
Accounts Receivable:		
Customers	94.6	56.4
Affiliated Companies	63.1	50.0
Accrued Unbilled Revenues	4.3	7.3
Miscellaneous	1.7	2.0
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	163.7	115.6
Fuel	33.1	31.4
Materials and Supplies	164.9	160.6
Risk Management Assets	14.4	7.6
Accrued Tax Benefits	59.2	58.4
Regulatory Asset for Under-Recovered Fuel Costs	4.3	15.0
Accrued Reimbursement of Spent Nuclear Fuel Costs	8.7	10.8
Prepayments and Other Current Assets	23.6	20.9
TOTAL CURRENT ASSETS	565.6	434.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,572.3	4,445.9
Transmission	1,529.8	1,504.0
Distribution	2,149.1	2,069.3
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	595.8	595.2
Construction Work in Progress	404.3	460.2
Total Property, Plant and Equipment	9,251.3	9,074.6
Accumulated Depreciation, Depletion and Amortization	3,057.3	3,024.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,194.0	6,050.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	562.6	579.4
Spent Nuclear Fuel and Decommissioning Trusts	2,554.9	2,527.6
Long-term Risk Management Assets	1.2	0.7
Deferred Charges and Other Noncurrent Assets	176.3	179.9
TOTAL OTHER NONCURRENT ASSETS	3,295.0	3,287.6
TOTAL ASSETS	$ 10,054.6	$ 9,772.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$—	$ 211.6
Accounts Payable:		
General	162.0	154.5
Affiliated Companies	78.0	98.3
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2018 and December 31, 2017 Amounts Include $104.2 and $96.3, Respectively, Related to DCC Fuel)	657.6	474.7
Risk Management Liabilities	5.4	3.5
Customer Deposits	37.6	37.7
Accrued Taxes	76.4	81.3
Accrued Interest	40.0	37.5
Obligations Under Capital Leases	5.7	5.8
Other Current Liabilities	86.1	106.4
TOTAL CURRENT LIABILITIES	1,148.8	1,211.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,439.2	2,270.4
Long-term Risk Management Liabilities	0.3	0.1
Deferred Income Taxes	1,004.2	953.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,710.6	1,708.7
Asset Retirement Obligations	1,350.5	1,321.6
Deferred Credits and Other Noncurrent Liabilities	93.0	88.5
TOTAL NONCURRENT LIABILITIES	6,597.8	6,343.1
TOTAL LIABILITIES	7,746.6	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	1,284.4	1,192.2
Accumulated Other Comprehensive Income (Loss)	(13.9)	(12.1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,308.0	2,217.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$10,054.6	$ 9,772.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$ 158.9	$ 78.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	121.9	99.8
Deferred Income Taxes	33.1	74.4
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(3.5)	31.6
Carrying Costs Income	(4.0)	(7.7)
Allowance for Equity Funds Used During Construction	(4.1)	(4.6)
Mark-to-Market of Risk Management Contracts	(5.2)	(12.3)
Amortization of Nuclear Fuel	51.4	71.6
Pension Contribution to Qualified Plan Trust	—	(13.0)
Deferred Fuel Over/Under-Recovery, Net	8.1	25.3
Change in Other Noncurrent Assets	(5.6)	(18.7)
Change in Other Noncurrent Liabilities	44.4	34.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(18.3)	33.5
Fuel, Materials and Supplies	(5.0)	(15.2)
Accounts Payable	(12.2)	9.0
Customer Deposits	(0.1)	2.3
Accrued Taxes, Net	0.8	13.0
Accrued Interest	2.5	0.1
Other Current Assets	1.2	15.9
Other Current Liabilities	(19.3)	(29.5)
Net Cash Flows from Operating Activities	345.0	389.2
INVESTING ACTIVITIES		
Construction Expenditures	(284.7)	(304.4)

Change in Advances to Affiliates, Net	(79.9)	(0.1)
Purchases of Investment Securities	(1,067.8)	(1,317.2)
Sales of Investment Securities	1,037.8	1,289.1
Acquisitions of Nuclear Fuel	(24.2)	(38.9)
Other Investing Activities	8.2	3.4
Net Cash Flows Used for Investing Activities	(410.6)	(368.1)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	700.6	411.5
Change in Advances from Affiliates, Net	(211.6)	(171.8)
Retirement of Long-term Debt – Nonaffiliated	(352.4)	(193.3)
Principal Payments for Capital Lease Obligations	(5.2)	(5.9)
Dividends Paid on Common Stock	(67.0)	(62.5)
Other Financing Activities	1.3	0.8
Net Cash Flows from (Used for) Financing Activities	65.7	(21.2)
Net Increase (Decrease) in Cash and Cash Equivalents	0.1	(0.1)
Cash and Cash Equivalents at Beginning of Period	1.3	1.2
Cash and Cash Equivalents at End of Period	$ 1.4	$ 1.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 55.2	$ 49.2
Net Cash Paid (Received) for Income Taxes	(23.6)	(56.9)
Noncash Acquisitions Under Capital Leases	3.2	2.6
Construction Expenditures Included in Current Liabilities as of June 30,	86.5	96.0
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	0.6	26.0
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.7	2.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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OHIO POWER COMPANY AND SUBSIDIARIES

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	3,287	2,861	7,420	6,554
Commercial	3,651	3,555	7,203	6,983
Industrial	3,796	3,690	7,350	7,259
Miscellaneous	26	27	57	59
Total Retail (a)	10,760	10,133	22,030	20,855
Wholesale (b)	534	490	1,201	1,164
Total KWhs	11,294	10,623	23,231	22,019

(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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	274	97	2,158	1,500
Normal – Heating (b)	186	186	2,070	2,085
Actual – Cooling (c)	454	312	458	315
Normal – Cooling (b)	291	287	294	290

(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.

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

Second Quarter of 2017	$62.3
Changes in Gross Margin:	
Retail Margins	64.1
Off-system Sales	11.0
Transmission Revenues	(2.4)
Other Revenues	(0.6)
Total Change in Gross Margin	72.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(68.1)
Depreciation and Amortization	(14.0)
Taxes Other Than Income Taxes	(4.1)
Interest Income	0.1
Allowance for Equity Funds Used During Construction	2.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.8
Interest Expense	0.8
Total Change in Expenses and Other	(80.0)
Income Tax Expense	14.4
Second Quarter of 2018	$68.8

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 $64 million primarily due to the following:
  - A $70 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $19 million increase in revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - An $8 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.

  These increases were partially offset by:
  - A $14 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - An $11 million decrease due to the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.
- Margins from Off-system Sales increased $11 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.

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

- Other Operation and Maintenance expenses increased $68 million primarily due to the following:
  - A $96 million increase in recoverable PJM expenses. This increase was offset within Gross Margins above.
  - A $19 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 $48 million decrease in PJM expenses related to the annual formula rate true-up that will be refunded in future periods.
- Depreciation and Amortization expenses increased $14 million primarily due to the following:
  - A $6 million increase in recoverable DIR depreciation expense. This increase was offset in Retail Margins above.
  - A $4 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $4 million primarily due to an 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 $14 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.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Reconciliation of Six Months Ended June 30, 2017 to Six Months Ended June 30, 2018 Net Income (in millions)	
Six Months Ended June 30, 2017	$148.5
Changes in Gross Margin:	
Retail Margins	95.9
Off-system Sales	18.2
Transmission Revenues	(8.8)
Other Revenues	(1.5)
Total Change in Gross Margin	103.8
Changes in Expenses and Other:	
Other Operation and Maintenance	(118.0)
Depreciation and Amortization	(21.5)
Taxes Other Than Income Taxes	(10.7)
Interest Income	(1.5)
Carrying Costs Income	(1.2)
Allowance for Equity Funds Used During Construction	2.6
Non-Service Cost Components of Net Periodic Benefit Cost	5.6
Interest Expense	0.6
Total Change in Expenses and Other	(144.1)
Income Tax Expense	40.2
Six Months Ended June 30, 2018	$148.4

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 $96 million primarily due to the following:
  - A $109 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $40 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 $14 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $9 million increase in usage primarily in the residential class.
  - A $5 million increase in state excise taxes due to an increase in metered KWh. This increase was offset by a corresponding increase in Taxes Other Than Income Taxes below.

  These increases were partially offset by:
  - A $30 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - An $18 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.
-

An $11 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues. This decrease was partially offset by a decrease in Other Operation and Maintenance expenses below.

- A $9 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations.
- A $9 million decrease in revenues associated with smart grid riders. This decrease was partially offset by a decrease in various expenses below.

- Margins from Off-system Sales increased $18 million primarily due to lower current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
- Transmission Revenues decreased $9 million due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $118 million primarily due to the following:
- A $131 million increase in recoverable PJM expenses. This increase was offset within Gross Margins above.
- A $40 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 $50 million decrease in PJM expenses related to the annual formula rate true-up that will be refunded in future periods.
- A $9 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 $22 million primarily due to the following:
- A $12 million increase in recoverable DIR depreciation expense. This increase was offset in Retail Margins above.
- A $7 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- Taxes Other Than Income Taxes increased $11 million primarily due to the following:
- A $5 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.
- A $5 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
- Non-Service Cost Components of Net Periodic Cost decreased $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 OPCo’s ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $40 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 and Six Months Ended June 30, 2018 and 2017
(in millions)
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
REVENUES				
Electricity, Transmission and Distribution	$735.9	$653.4	$1,522.2	$1,391.8
Sales to AEP Affiliates	11.5	9.1	14.6	14.8
Other Revenues	1.4	1.4	2.9	3.4
TOTAL REVENUES	748.8	663.9	1,539.7	1,410.0
EXPENSES				
Purchased Electricity for Resale	162.9	156.4	368.4	344.7
Purchased Electricity from AEP Affiliates	27.9	24.7	58.1	56.7
Amortization of Generation Deferrals	56.4	53.3	115.0	114.2
Other Operation	199.0	131.7	371.2	254.0
Maintenance	34.1	33.3	71.3	70.5
Depreciation and Amortization	65.1	51.1	129.9	108.4
Taxes Other Than Income Taxes	99.0	94.9	204.1	193.4
TOTAL EXPENSES	644.4	545.4	1,318.0	1,141.9
OPERATING INCOME	104.4	118.5	221.7	268.1
Other Income (Expense):				
Interest Income	0.9	0.8	1.8	3.3
Carrying Costs Income	0.6	0.6	1.3	2.5
Allowance for Equity Funds Used During Construction	3.3	0.8	5.8	3.2
Non-Service Cost Components of Net Periodic Benefit Cost	3.9	1.1	7.8	2.2
Interest Expense	(25.3)	(26.1)	(50.5)	(51.1)
INCOME BEFORE INCOME TAX EXPENSE	87.8	95.7	187.9	228.2
Income Tax Expense	19.0	33.4	39.5	79.7
NET INCOME	$68.8	$62.3	$148.4	$148.5

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

See Condensed Notes to

Condensed Financial Statements of Registrants beginning on page 137.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net Income	$68.8	$62.3	$148.4	$148.5
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.2) for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(0.2) and $(0.3) for the Six Months Ended June 30, 2018 and 2017, Respectively	(0.3)	(0.3)	(0.6)	(0.5)
TOTAL COMPREHENSIVE INCOME	$68.5	$62.0	$147.8	$148.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 321.2	$ 838.8	$ 954.5	$ 3.0	$ 2,117.5
Common Stock Dividends			(130.0)		(130.0)
Net Income			148.5		148.5
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2017	$ 321.2	$ 838.8	$ 973.0	$ 2.5	$ 2,135.5
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 321.2	$ 838.8	$ 1,148.4	$ 1.9	$ 2,310.3
Common Stock Dividends			(225.0)		(225.0)
ASU 2018-02 Adoption				0.4	0.4
Net Income			148.4		148.4
Other Comprehensive Loss				(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	$ 321.2	$ 838.8	$ 1,071.8	$ 1.7	$ 2,233.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$3.3	$ 3.1
Restricted Cash for Securitized Funding	26.5	26.6
Accounts Receivable:		
Customers	128.4	67.8
Affiliated Companies	75.8	70.2
Accrued Unbilled Revenues	21.7	29.7
Miscellaneous	0.7	1.9
Allowance for Uncollectible Accounts	(0.6)	(0.6)
Total Accounts Receivable	226.0	169.0
Materials and Supplies	40.0	41.9
Renewable Energy Credits	22.2	25.0
Risk Management Assets	0.4	0.6
Regulatory Asset for Under-Recovered Fuel Costs	56.3	115.9
Prepayments and Other Current Assets	28.3	15.8
TOTAL CURRENT ASSETS	403.0	397.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,460.1	2,419.2
Distribution	4,740.9	4,626.4
Other Property, Plant and Equipment	532.6	495.9
Construction Work in Progress	445.2	410.1
Total Property, Plant and Equipment	8,178.8	7,951.6
Accumulated Depreciation and Amortization	2,218.6	2,184.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,960.2	5,766.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	480.0	652.8
Securitized Assets	25.1	37.7
Long-term Risk Management Assets	0.1	—
Deferred Charges and Other Noncurrent Assets	324.2	406.5
TOTAL OTHER NONCURRENT ASSETS	829.4	1,097.0
TOTAL ASSETS	$7,192.6	$ 7,261.7

See Condensed Notes to Condensed Financial Statements

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

	June 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$213.9	$ 87.8
Accounts Payable:		
General	160.1	205.8
Affiliated Companies	95.3	118.2
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2018 and December 31, 2017 Amounts Include $47.5 and $47, Respectively, Related to Ohio Phase-in-Recovery Funding)	47.5	397.0
Risk Management Liabilities	4.8	6.4
Customer Deposits	77.6	69.2
Accrued Taxes	341.5	512.5
Other Current Liabilities	187.0	196.9
TOTAL CURRENT LIABILITIES	1,127.7	1,593.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2018 and December 31, 2017 Amounts Include $24.3 and $47.5, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,692.5	1,322.3
Long-term Risk Management Liabilities	82.0	126.0
Deferred Income Taxes	751.4	762.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,222.4	1,100.2
Deferred Credits and Other Noncurrent Liabilities	83.1	46.2
TOTAL NONCURRENT LIABILITIES	3,831.4	3,357.6
TOTAL LIABILITIES	4,959.1	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	1,071.8	1,148.4
Accumulated Other Comprehensive Income (Loss)	1.7	1.9
TOTAL COMMON SHAREHOLDER'S EQUITY	2,233.5	2,310.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$7,192.6	$ 7,261.7

See
Condensed

Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$148.4	$148.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	129.9	108.4
Amortization of Generation Deferrals	115.0	114.2
Deferred Income Taxes	(12.5)	94.5
Carrying Costs Income	(1.3)	(2.5)
Allowance for Equity Funds Used During Construction	(5.8)	(3.2)
Mark-to-Market of Risk Management Contracts	(45.5)	11.8
Pension Contributions to Qualified Plan Trust	—	(8.2)
Property Taxes	129.6	117.2
Provision for Refund – Global Settlement, Net	(5.5)	(88.1)
Change in Other Noncurrent Assets	83.3	(93.1)
Change in Other Noncurrent Liabilities	56.0	41.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	14.0	18.3
Materials and Supplies	(3.6)	(7.4)
Accounts Payable	(39.9)	(6.8)
Accrued Taxes, Net	(169.5)	(252.5)
Other Current Assets	(0.6)	(9.6)
Other Current Liabilities	(11.4)	(25.3)
Net Cash Flows from Operating Activities	380.6	158.0
INVESTING ACTIVITIES		
Construction Expenditures	(312.8)	(224.5)
Change in Advances to Affiliates, Net	—	24.2
Other Investing Activities	12.7	4.9
Net Cash Flows Used for Investing Activities	(300.1)	(195.4)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	392.9	—
Change in Advances from Affiliates, Net	126.1	190.5
Retirement of Long-term Debt – Nonaffiliated	(372.9)	(22.5)
Principal Payments for Capital Lease Obligations	(1.9)	(2.0)
Dividends Paid on Common Stock	(225.0)	(130.0)
Other Financing Activities	0.4	0.6
Net Cash Flows from (Used for) Financing Activities	(80.4)	36.6
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	0.1	(0.8)
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	$29.8	$29.5

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$48.3	$50.0
Net Cash Paid for Income Taxes	45.1	76.8
Noncash Acquisitions Under Capital Leases	1.9	1.9
Construction Expenditures Included in Current Liabilities as of June 30,	64.5	50.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

PUBLIC SERVICE COMPANY OF OKLAHOMA

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

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	1,635	1,358	3,128	2,670
Commercial	1,390	1,308	2,552	2,438
Industrial	1,496	1,471	2,836	2,777
Miscellaneous	333	316	609	589
Total Retail	4,854	4,453	9,125	8,474
Wholesale	205	146	362	227
Total KWhs	5,059	4,599	9,487	8,701

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	129	12	1,161	682
Normal – Heating (b)	40	41	1,081	1,103
Actual – Cooling (c)	907	629	919	688
Normal – Cooling (b)	650	655	667	669

(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.

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

Second Quarter of 2017	$20.4
Changes in Gross Margin:	
Retail Margins (a)	34.2
Off-system Sales	0.1
Transmission Revenues	(0.6)
Other Revenues	0.4
Total Change in Gross Margin	34.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(12.8)
Depreciation and Amortization	(8.8)
Taxes Other Than Income Taxes	(0.6)
Other Income (Loss)	(0.1)
Non-Service Cost Components of Net Periodic Benefit Cost	1.4
Interest Expense	(2.9)
Total Change in Expenses and Other	(23.8)
Income Tax Expense	5.9
Second Quarter of 2018	$36.6

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

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

- Retail Margins increased $34 million primarily due to the following:
  - A $21 million increase in weather-related usage due to a 44% increase in cooling degree days.
  - A $13 million increase due to new rates implemented in March 2018, inclusive of an $8 million decrease due to the change in the corporate federal tax rate.
  - A $9 million increase in revenue from rate riders. This increase in Retail Margins was partially offset by corresponding increases to riders/trackers recognized in other expense items below.

  These increases were partially offset by:
  - A $7 million decrease related to the System Reliability Rider (SRR) that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
  - A $3 million decrease due to 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $13 million primarily due the following:
- A $15 million increase in transmission expenses primarily due to increased SPP transmission services.
- A $5 million increase due to the Wind Catcher Project.
- A $5 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 $10 million decrease due to a probable refund associated with transmission expenses incurred in prior periods.
- A $2 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 $9 million primarily due to a higher depreciable base.
- Interest Expense increased $3 million primarily due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
- Income Tax Expense decreased $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 and amortization of Excess ADIT associated with certain depreciable property, partially offset by an increase in pretax book income.

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

Six Months Ended June 30, 2017	$25.2
Changes in Gross Margin:	
Retail Margins (a)	34.0
Off-system Sales	0.2
Transmission Revenues	(0.6)
Total Change in Gross Margin	33.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(24.0)
Depreciation and Amortization	(12.1)
Taxes Other Than Income Taxes	(1.6)
Other Income (Loss)	(0.6)
Non-Service Cost Components of Net Periodic Benefit Cost	2.7
Interest Expense	(4.0)
Total Change in Expenses and Other	(39.6)
Income Tax Expense	10.2
Six Months Ended June 30, 2018	$29.4

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

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

- Retail Margins increased $34 million primarily due to the following:
  - A $24 million increase in weather-related usage due to a 70% increase in heating degree days and 34% increase in cooling degree days.
  - A $17 million increase due to new rates implemented in March 2018, inclusive of a $10 million decrease due to the change in the corporate federal tax rate.
  - A $13 million increase in revenue from rate riders. This increase in Retail Margins was partially offset by corresponding increases to riders/trackers recognized in other expense items below.
  - A $2 million increase due to higher weather-normalized margins.

  These increases were partially offset by:
  - A $12 million decrease related to the SRR that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
  - A $10 million decrease due to 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.

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

- Other Operation and Maintenance expenses increased $24 million primarily due to the following:
- A $24 million increase in transmission expenses primarily due to increased SPP transmission services.
- A $9 million increase due to the Wind Catcher Project.
- An $8 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 $10 million decrease due to a probable refund associated with transmission expenses incurred in prior periods.
- An $8 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 $12 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 PSO’s ability to capitalize a portion of its non-service cost components.
- Interest Expense increased $4 million primarily due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
- Income Tax Expense decreased $10 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT associated with certain depreciable property and a decrease in pretax book income.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$395.3	$342.6	$730.4	$644.5
Sales to AEP Affiliates	1.5	1.0	2.6	2.1
Other Revenues	1.5	1.1	2.1	2.2
TOTAL REVENUES	398.3	344.7	735.1	648.8
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	58.7	25.6	107.1	37.9
Purchased Electricity for Resale	113.1	126.7	235.5	252.0
Other Operation	93.7	76.1	180.5	144.4
Maintenance	24.0	28.8	50.9	63.0
Depreciation and Amortization	41.4	32.6	78.2	66.1
Taxes Other Than Income Taxes	10.2	9.6	21.8	20.2
TOTAL EXPENSES	341.1	299.4	674.0	583.6
OPERATING INCOME	57.2	45.3	61.1	65.2
Other Income (Expense):				
Other Income (Loss)	(0.1)	—	(0.1)	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.2	0.8	4.4	1.7
Interest Expense	(16.3)	(13.4)	(31.0)	(27.0)
INCOME BEFORE INCOME TAX EXPENSE	43.0	32.7	34.4	40.4
Income Tax Expense	6.4	12.3	5.0	15.2
NET INCOME	$36.6	$20.4	$29.4	$25.2

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

See Condensed Notes to Condensed Financial Statements of

Registrants
beginning on
page 137.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net Income	$36.6	$20.4	$29.4	$25.2
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(0.2) and $(0.2) for the Six Months Ended June 30, 2018 and 2017, Respectively	(0.3)	(0.2)	(0.5)	(0.4)
TOTAL COMPREHENSIVE INCOME	$36.3	$20.2	$28.9	$24.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 157.2	$ 364.0	$ 689.5	$ 3.4	$ 1,214.1
Common Stock Dividends			(35.0)		(35.0)
Net Income			25.2		25.2
Other Comprehensive Loss				(0.4)	(0.4)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2017	$ 157.2	$ 364.0	$ 679.7	$ 3.0	$ 1,203.9
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 157.2	$ 364.0	$ 691.5	$ 2.6	$ 1,215.3
Common Stock Dividends			(25.0)		(25.0)
ASU 2018-02 Adoption				0.5	0.5
Net Income			29.4		29.4
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	$ 157.2	$ 364.0	$ 695.9	$ 2.6	$ 1,219.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$1.6	$ 1.6
Accounts Receivable:		
Customers	29.7	32.5
Affiliated Companies	42.9	32.9
Miscellaneous	3.2	4.1
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	75.8	69.4
Fuel	11.8	12.5
Materials and Supplies	43.5	42.0
Risk Management Assets	24.5	6.4
Accrued Tax Benefits	20.4	28.1
Regulatory Asset for Under-Recovered Fuel Costs	7.4	36.7
Prepayments and Other Current Assets	7.7	8.6
TOTAL CURRENT ASSETS	192.7	205.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,574.7	1,577.2
Transmission	871.4	858.8
Distribution	2,503.7	2,445.1
Other Property, Plant and Equipment	301.4	287.4
Construction Work in Progress	103.1	111.3
Total Property, Plant and Equipment	5,354.3	5,279.8
Accumulated Depreciation and Amortization	1,439.3	1,393.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,915.0	3,886.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	362.9	368.1
Employee Benefits and Pension Assets	40.8	40.0
Deferred Charges and Other Noncurrent Assets	23.8	8.7
TOTAL OTHER NONCURRENT ASSETS	427.5	416.8
TOTAL ASSETS	$4,535.2	$ 4,508.3

See
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Statements
of

Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$118.4	$ 149.6
Accounts Payable:		
General	125.7	102.4
Affiliated Companies	48.0	48.0
Long-term Debt Due Within One Year – Nonaffiliated	0.5	0.5
Customer Deposits	55.3	54.1
Accrued Taxes	40.0	22.6
Accrued Interest	13.3	14.1
Other Current Liabilities	45.9	44.7
TOTAL CURRENT LIABILITIES	447.1	436.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,286.3	1,286.0
Deferred Income Taxes	635.0	642.0
Regulatory Liabilities and Deferred Investment Tax Credits	851.8	853.5
Asset Retirement Obligations	54.1	53.0
Deferred Credits and Other Noncurrent Liabilities	41.2	22.5
TOTAL NONCURRENT LIABILITIES	2,868.4	2,857.0
TOTAL LIABILITIES	3,315.5	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	695.9	691.5
Accumulated Other Comprehensive Income (Loss)	2.6	2.6
TOTAL COMMON SHAREHOLDER'S EQUITY	1,219.7	1,215.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$4,535.2	$ 4,508.3

See
Condensed
Notes to
Condensed
Financial

Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30, 2018		2017	
OPERATING ACTIVITIES				
Net Income	$ 29.4		$ 25.2	
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization	78.2		66.1	
Deferred Income Taxes	(6.5	)	53.7	
Allowance for Equity Funds Used During Construction	0.1		(0.4	)
Mark-to-Market of Risk Management Contracts	(18.1	)	(8.7	)
Pension Contributions to Qualified Plan Trust	—		(5.3	)
Property Taxes	(19.2	)	(18.9	)
Deferred Fuel Over/Under-Recovery, Net	29.9		(29.6	)
Change in Other Noncurrent Assets	1.4		(18.6	)
Change in Other Noncurrent Liabilities	14.8		(0.7	)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net	(6.4	)	5.6	
Fuel, Materials and Supplies	(0.8	)	8.2	
Accounts Payable	23.0		9.0	
Accrued Taxes, Net	30.0		24.0	
Other Current Assets	0.5		(1.2	)
Other Current Liabilities	3.0		(26.0	)
Net Cash Flows from Operating Activities	159.3		82.4	
INVESTING ACTIVITIES				
Construction Expenditures	(104.2	)	(136.2	)
Other Investing Activities	2.7		1.3	
Net Cash Flows Used for Investing Activities	(101.5	)	(134.9	)
FINANCING ACTIVITIES				
Change in Advances from Affiliates, Net	(31.2	)	89.4	

Retirement of Long-term Debt – Nonaffiliated	(0.2		)	(0.2		)
Principal Payments for Capital Lease Obligations	(1.8		)	(2.0		)
Dividends Paid on Common Stock	(25.0		)	(35.0		)
Other Financing Activities	0.4			0.2		
Net Cash Flows from (Used for) Financing Activities	(57.8		)	52.4		
Net Decrease in Cash and Cash Equivalents	—			(0.1		)
Cash and Cash Equivalents at Beginning of Period	1.6			1.5		
Cash and Cash Equivalents at End of Period	$	1.6		$	1.4	
SUPPLEMENTARY INFORMATION						
Cash Paid for Interest, Net of Capitalized Amounts	$	31.7		$	31.7	
Net Cash Paid (Received) for Income Taxes	(1.8		)	(42.9		)
Noncash Acquisitions Under Capital Leases	1.8			0.9		
Construction Expenditures Included in Current Liabilities as of June 30,	25.9			29.2		

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

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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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in millions of KWhs)			
Retail:				
Residential	1,606	1,350	3,164	2,660
Commercial	1,630	1,484	2,918	2,789
Industrial	1,423	1,334	2,622	2,556
Miscellaneous	21	21	40	41
Total Retail	4,680	4,189	8,744	8,046
Wholesale	1,563	1,742	3,471	4,181
Total KWhs	6,243	5,931	12,215	12,227

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		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
	(in degree days)			
Actual – Heating (a)	55	6	784	394
Normal – Heating (b)	25	26	732	746
Actual – Cooling (c)	895	645	955	751
Normal – Cooling (b)	733	737	771	771

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

Second Quarter of 2017	$24.5
Changes in Gross Margin:	
Retail Margins (a)	28.2
Off-system Sales	(0.5)
Transmission Revenues	(5.2)
Other Revenues	(0.3)
Total Change in Gross Margin	22.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(19.1)
Depreciation and Amortization	(6.5)
Taxes Other Than Income Taxes	(0.2)
Interest Income	0.2
Allowance for Equity Funds Used During Construction	0.9
Non-Service Cost Components of Net Periodic Benefit Cost	1.4
Total Change in Expenses and Other	(23.3)
Income Tax Expense	7.8
Equity Earnings (Loss) of Unconsolidated Subsidiary	6.9
Net Income Attributable to Noncontrolling Interest	(0.5)
Second Quarter of 2018	$37.6

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

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

- Retail Margins increased $28 million primarily due to the following:
  - A $20 million increase in weather-related usage primarily due to a 39% increase in cooling degree days.
  - An $18 million increase primarily due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
  - A $4 million increase due to higher weather-normalized margins.

  These increases were partially offset by:
  - A $15 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
- Transmission Revenues decreased $5 million primarily due to an $11 million 2018 provision for refund related to revenues recorded in prior periods on certain transmission assets that management believes should not have been included in the SPP formula rate. This decrease is partially offset by an increase in transmission investments in SPP.

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

- Other Operation and Maintenance expenses increased $19 million primarily due to the following:

- A $12 million increase due to the Wind Catcher Project.
- A $12 million increase in SPP transmission services.

These increases were partially offset by:

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- An $8 million decrease due to a probable refund associated with transmission expenses incurred in prior periods.
- Depreciation and Amortization expenses increased $6 million primarily due to a higher depreciable base.
- Income Tax Expense decreased $8 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and amortization of Excess ADIT associated with certain depreciable property, partially offset by an increase in pretax book income.
- Equity Earnings (Loss) of Unconsolidated Subsidiary increased $7 million primarily due to a prior period income tax adjustment recognized in 2017.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Reconciliation of Six Months Ended June 30, 2017 to Six Months Ended June 30, 2018
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Six Months Ended June 30, 2017	$40.8
Changes in Gross Margin:	
Retail Margins (a)	38.4
Off-system Sales	(1.6)
Transmission Revenues	(2.5)
Other Revenues	(0.2)
Total Change in Gross Margin	34.1
Changes in Expenses and Other:	
Other Operation and Maintenance	(33.9)
Depreciation and Amortization	(13.1)
Taxes Other Than Income Taxes	(1.9)
Interest Income	1.1
Allowance For Equity Funds Used During Construction	2.4
Non-Service Cost Components of Net Periodic Benefit Cost	2.8
Interest Expense	(2.3)
Total Change in Expenses and Other	(44.9)
Income Tax Expense	14.4
Equity Earnings (Loss) of Unconsolidated Subsidiary	6.1
Net Income Attributable to Noncontrolling Interest	(1.1)
Six Months Ended June 30, 2018	$49.4

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

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

- Retail Margins increased $38 million primarily due to the following:
  - A $39 million increase primarily due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
  - A $34 million increase in weather-related usage primarily due to a 99% increase in heating degree days and a 27% increase in cooling degree days.

  These increases were partially offset by:
  - A $27 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $10 million decrease due to lower weather-normalized margins, primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
- Transmission Revenues decreased $3 million primarily due to an $11 million 2018 provision for refund related to revenues recorded in prior periods on certain transmission assets that management believes should not have been included in the SPP formula rate. This decrease is partially offset by an increase in transmission investments in SPP.

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

- Other Operation and Maintenance expenses increased $34 million primarily due to the following:
  - A $22 million increase due to the Wind Catcher Project.
  - A $17 million increase in SPP transmission services.

  These increases were partially offset by:
  - An $8 million decrease due to a probable refund associated with transmission expenses incurred in prior periods.
- Depreciation and Amortization expenses increased $13 million primarily due to a higher depreciable base and higher depreciation rates from the 2017 Texas base case order.
- 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 SWEPCo's ability to capitalize a portion of its non-service cost components.
- Income Tax Expense decreased $14 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT associated with certain depreciable property and a decrease in pretax book income.
- Equity Earnings (Loss) of Unconsolidated Subsidiary increased $6 million primarily due to a prior period income tax adjustment recognized in 2017.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
REVENUES				
Electric Generation, Transmission and Distribution	$451.4	$416.0	$864.4	$812.3
Sales to AEP Affiliates	5.4	8.1	11.5	12.7
Other Revenues	0.3	0.6	0.6	1.0
TOTAL REVENUES	457.1	424.7	876.5	826.0
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	114.5	111.4	241.3	242.3
Purchased Electricity for Resale	53.4	46.3	96.1	78.7
Other Operation	98.0	74.8	192.9	153.7
Maintenance	37.6	41.7	68.6	73.9
Depreciation and Amortization	58.6	52.1	116.0	102.9
Taxes Other Than Income Taxes	24.5	24.3	49.5	47.6
TOTAL EXPENSES	386.6	350.6	764.4	699.1
OPERATING INCOME	70.5	74.1	112.1	126.9
Other Income (Expense):				
Interest Income	0.6	0.4	2.4	1.3
Allowance for Equity Funds Used During Construction	0.9	—	3.2	0.8
Non-Service Cost Components of Net Periodic Benefit Cost	2.3	0.9	4.6	1.8
Interest Expense	(30.9)	(30.9)	(63.1)	(60.8)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	43.4	44.5	59.2	70.0
Income Tax Expense	5.4	13.2	8.3	22.7
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.7	(6.2)	1.2	(4.9)
NET INCOME	38.7	25.1	52.1	42.4
Net Income Attributable to Noncontrolling Interest	1.1	0.6	2.7	1.6
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$37.6	$24.5	$49.4	$40.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net Income	$38.7	$25.1	$52.1	$42.4
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.2 for the Three Months Ended June 30, 2018 and 2017, Respectively, and $0.2 and $0.4 for the Six Months Ended June 30, 2018 and 2017, Respectively	0.5	0.2	0.9	0.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended June 30, 2018 and 2017, Respectively, and $(0.2) and $(0.2) for the Six Months Ended June 30, 2018 and 2017, Respectively	(0.4)	(0.1)	(0.7)	(0.3)
TOTAL OTHER COMPREHENSIVE INCOME	0.1	0.1	0.2	0.4
TOTAL COMPREHENSIVE INCOME	38.8	25.2	52.3	42.8
Total Comprehensive Income Attributable to Noncontrolling Interest	1.1	0.6	2.7	1.6
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$37.7	$24.6	$49.6	$41.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2018 and 2017
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2016	$135.7	$676.6	$1,411.9	$ (9.4)	$ 0.4	$2,215.2
Common Stock Dividends			(55.0)			(55.0)
Common Stock Dividends – Nonaffiliated					(1.7)	(1.7)
Net Income			40.8		1.6	42.4
Other Comprehensive Income				0.4		0.4
TOTAL EQUITY – JUNE 30, 2017	$135.7	$676.6	$1,397.7	$ (9.0)	$ 0.3	$2,201.3
TOTAL EQUITY – DECEMBER 31, 2017	$135.7	$676.6	$1,426.6	$ (4.0)	$ (0.4)	$2,234.5
Common Stock Dividends			(40.0)			(40.0)
Common Stock Dividends – Nonaffiliated					(1.8)	(1.8)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			49.4		2.7	52.1
Other Comprehensive Income				0.2		0.2
TOTAL EQUITY – JUNE 30, 2018	$135.7	$676.6	$1,435.6	$ (4.7)	$ 0.5	$2,243.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$2.1	$ 1.6
Advances to Affiliates	2.0	2.0
Accounts Receivable:		
Customers	45.1	70.9
Affiliated Companies	38.3	30.2
Miscellaneous	21.0	25.8
Allowance for Uncollectible Accounts	(0.5)	(1.3)
Total Accounts Receivable	103.9	125.6
Fuel (June 30, 2018 and December 31, 2017 Amounts Include $37.8 and $41.5, Respectively, Related to Sabine)	121.2	123.6
Materials and Supplies	69.1	67.9
Risk Management Assets	7.4	6.4
Regulatory Asset for Under-Recovered Fuel Costs	16.0	14.1
Prepayments and Other Current Assets	42.0	39.2
TOTAL CURRENT ASSETS	363.7	380.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,636.3	4,624.9
Transmission	1,795.2	1,679.8
Distribution	2,124.4	2,095.8
Other Property, Plant and Equipment (June 30, 2018 and December 31, 2017 Amounts Include $265.6 and $266.7, Respectively, Related to Sabine)	733.9	684.1
Construction Work in Progress	228.6	233.2
Total Property, Plant and Equipment	9,518.4	9,317.8
Accumulated Depreciation and Amortization (June 30, 2018 and December 31, 2017 Amounts Include $171 and $165.9, Respectively, Related to Sabine)	2,759.3	2,685.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,759.1	6,632.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	221.4	220.6
Deferred Charges and Other Noncurrent Assets	149.3	109.9
TOTAL OTHER NONCURRENT ASSETS	370.7	330.5
TOTAL ASSETS	$7,493.5	$ 7,342.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	June 30, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$119.9	$ 118.7
Accounts Payable:		
General	120.4	160.4
Affiliated Companies	53.2	63.7
Short-term Debt – Nonaffiliated	25.2	22.0
Long-term Debt Due Within One Year – Nonaffiliated	457.2	3.7
Risk Management Liabilities	—	0.2
Customer Deposits	64.0	62.1
Accrued Taxes	80.4	39.0
Accrued Interest	39.0	38.9
Obligations Under Capital Leases	11.1	11.2
Other Current Liabilities	93.0	78.7
TOTAL CURRENT LIABILITIES	1,063.4	598.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,046.5	2,438.2
Long-term Risk Management Liabilities	2.3	—
Deferred Income Taxes	926.6	917.7
Regulatory Liabilities and Deferred Investment Tax Credits	898.0	896.4
Asset Retirement Obligations	180.0	160.3
Employee Benefits and Pension Obligations	18.9	19.5
Obligations Under Capital Leases	55.0	57.8
Deferred Credits and Other Noncurrent Liabilities	59.1	19.9
TOTAL NONCURRENT LIABILITIES	4,186.4	4,509.8
TOTAL LIABILITIES	5,249.8	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	1,435.6	1,426.6
Accumulated Other Comprehensive Income (Loss)	(4.7)	(4.0)
TOTAL COMMON SHAREHOLDER’S EQUITY	2,243.2	2,234.9
Noncontrolling Interest	0.5	(0.4)

TOTAL EQUITY	2,243.7	2,234.5
TOTAL LIABILITIES AND EQUITY	$7,493.5	$ 7,342.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

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

	Six Months Ended June 30, 2018	2017
OPERATING ACTIVITIES		
Net Income	$ 52.1	$ 42.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	116.0	102.9
Deferred Income Taxes	0.4	68.7
Allowance for Equity Funds Used During Construction	(3.2)	(0.8)
Mark-to-Market of Risk Management Contracts	1.1	(11.4)
Pension Contributions to Qualified Plan Trust	—	(8.9)
Property Taxes	(31.6)	(30.8)
Deferred Fuel Over/Under-Recovery, Net	0.8	(3.1)
Change in Other Noncurrent Assets	(7.6)	(3.3)
Change in Other Noncurrent Liabilities	45.4	(11.1)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	22.1	22.0
Fuel, Materials and Supplies	1.2	3.1
Accounts Payable	(17.3)	13.2
Accrued Taxes, Net	31.8	48.8
Other Current Assets	4.5	9.3
Other Current Liabilities	10.5	(24.1)
Net Cash Flows from Operating Activities	226.2	216.9
INVESTING ACTIVITIES		
Construction Expenditures	(244.6)	(164.7)
Change in Advances to Affiliates, Net	—	167.8
Other Investing Activities	0.6	3.3
Net Cash Flows from (Used for) Investing Activities	(244.0)	6.4
FINANCING ACTIVITIES		

Issuance of Long-term Debt – Nonaffiliated	444.6	114.7
Change in Short-term Debt – Nonaffiliated	3.2	8.7
Change in Advances from Affiliates, Net	1.2	58.6
Retirement of Long-term Debt – Nonaffiliated	(383.5)	(351.8)
Principal Payments for Capital Lease Obligations	(5.7)	(5.7)
Dividends Paid on Common Stock	(40.0)	(55.0)
Dividends Paid on Common Stock – Nonaffiliated	(1.8)	(1.7)
Other Financing Activities	0.3	0.3
Net Cash Flows from (Used for) Financing Activities	18.3	(231.9)
Net Increase (Decrease) in Cash and Cash Equivalents	0.5	(8.6)
Cash and Cash Equivalents at Beginning of Period	1.6	10.3
Cash and Cash Equivalents at End of Period	$ 2.1	$ 1.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 59.7	$ 66.8
Net Cash Paid (Received) for Income Taxes	16.3	(56.5)
Noncash Acquisitions Under Capital Leases	2.7	1.8
Construction Expenditures Included in Current Liabilities as of June 30,	39.5	50.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 137.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and six months ended June 30, 2018 is not necessarily indicative of results that may be expected for the year ending December 31, 2018. The condensed financial statements are unaudited and should be read in conjunction with the audited 2017 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 22, 2018.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Three Months Ended June 30,			
	2018		2017	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$528.4		$375.0	
Weighted Average Number of Basic Shares Outstanding	492.7	$ 1.07	491.8	$ 0.76
Weighted Average Dilutive Effect of Stock-Based Awards	0.8	—	0.8	—
Weighted Average Number of Diluted Shares Outstanding	493.5	$ 1.07	492.6	$ 0.76

	Six Months Ended June 30,			
	2018		2017	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$982.8		$967.2	
Weighted Average Number of Basic Shares Outstanding	492.5	$2.00	491.8	$1.97
Weighted Average Dilutive Effect of Stock-Based Awards	0.8	(0.01)	0.5	(0.01)
Weighted Average Number of Diluted Shares Outstanding	493.3	$1.99	492.3	$1.96

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

Nonconsolidated Variable Interest Entity (Applies to AEP and SWEPCo)

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

Transmission Formula Rates (Applies to AEPTCo)

In the second quarter of 2018, AEPTCo management identified certain transmission assets that it believes should not have been included in AEPTCo's SPP transmission formula rates. As a result, in the second quarter of 2018, AEPTCo recorded a $17 million out of period correction of an error related to revenue recorded from 2013 through March 31, 2018. Management has determined the effect of the correction was not material to the current period financial statements or any previously issued financial statements.

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:

	June 30, 2018			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			
Cash and Cash Equivalents	$211.2	$0.1	$2.8	$3.3
Restricted Cash	176.1	131.9	17.7	26.5
Total Cash, Cash Equivalents and Restricted Cash	$387.3	$132.0	$20.5	$29.8

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

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

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

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

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

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

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

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

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with 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 and the process of implementing a compliant lease system solution continues. 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.

In July 2018, the FASB issued ASU 2018-10 “Codification Improvements to Topic 842, Leases” to clarify certain narrow aspects of the guidance in ASU 2016-02. The effective date and transmission requirements in ASU 2018-10 are the same as the requirements in ASU 2016-02. Management is currently assessing the potential impacts of ASU 2018-10 in context of the overall adoption of the new accounting guidance for leases. In addition, management continues to monitor both the FASB’s ongoing standard-setting activities that may result in the issuance of additional targeted improvements, as well as potential industry implementation issues. Management plans to adopt ASU 2016-02 and ASU 2018-10 effective January 1, 2019.

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

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

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

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

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

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

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

In August 2017, the FASB issued ASU 2017-12 amending the recognition and presentation requirements for hedge accounting activities. The objectives are to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements and reduce the complexity of applying hedge accounting. Among other things, ASU 2017-12: (a) expands the types of transactions eligible for hedge accounting, (b) eliminates the separate measurement and presentation of hedge ineffectiveness, (c) simplifies the requirements around the assessment of hedge effectiveness, (d) provides companies more time to finalize hedge documentation and (e) enhances presentation and disclosure requirements.

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

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

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

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

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the three and six months ended June 30, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

AEP

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

	Cash Flow Hedges			
	Commodity	Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of March 31, 2018	$(32.0)	$(15.5)	$(47.9)	$(95.4)
Change in Fair Value Recognized in AOCI	5.4	—	—	5.4
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale (a)	(4.7)	—	—	(4.7)
Interest Expense (a)	—	0.2	—	0.2
Amortization of Prior Service Cost (Credit)	—	—	(4.7)	(4.7)
Amortization of Actuarial (Gains)/Losses	—	—	3.2	3.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	(4.7)	0.2	(1.5)	(6.0)
Income Tax (Expense) Credit	(0.9)	—	(0.3)	(1.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(3.8)	0.2	(1.2)	(4.8)
Net Current Period Other Comprehensive Income (Loss)	1.6	0.2	(1.2)	0.6
Balance in AOCI as of June 30, 2018	$(30.4)	$(15.3)	$(49.1)	$(94.8)

AEP

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

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of March 31, 2017	$(39.6)	$(15.3)	$ 9.6	$(125.7)	$(171.0)
Change in Fair Value Recognized in AOCI	(1.8)	4.7	0.6	—	3.5
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (a)	8.3	—	—	—	8.3
Interest Expense (a)	—	0.3	—	—	0.3

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	8.3	0.3	—	0.4	9.0
Income Tax (Expense) Credit	2.9	0.1	—	0.1	3.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	5.4	0.2	—	0.3	5.9
Net Current Period Other Comprehensive Income (Loss)	3.6	4.9	0.6	0.3	9.4
Balance in AOCI as of June 30, 2017	$(36.0)	$(10.4)	$ 10.2	$(125.4)	$(161.6)

AEP

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

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2017	$(28.4)	$(13.0)	$ 11.9	$(38.3)	$(67.8)
Change in Fair Value Recognized in AOCI	18.2	—	—	—	18.2
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (a)	(17.8)	—	—	—	(17.8)
Interest Expense (a)	—	0.5	—	—	0.5
Amortization of Prior Service Cost (Credit)	—	—	—	(9.7)	(9.7)
Amortization of Actuarial (Gains)/Losses	—	—	—	6.4	6.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	(17.8)	0.5	—	(3.3)	(20.6)
Income Tax (Expense) Credit	(3.7)	0.1	—	(0.7)	(4.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(14.1)	0.4	—	(2.6)	(16.3)
Net Current Period Other Comprehensive Income (Loss)	4.1	0.4	—	(2.6)	1.9
ASU 2018-02 Adoption (b)	(6.1)	(2.7)	—	(8.2)	(17.0)
ASU 2016-01 Adoption (b)	—	—	(11.9)	—	(11.9)
Balance in AOCI as of June 30, 2018	$(30.4)	$(15.3)	$ —	$(49.1)	$(94.8)

AEP

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

	Cash Flow Hedges				
	Commodity	Interest Rate	Securities Available for Sale	Pension and OPEB	Total
	(in millions)				
Balance in AOCI as of December 31, 2016	$(23.1)	$(15.7)	$ 8.4	$(125.9)	$(156.3)
Change in Fair Value Recognized in AOCI	(23.6)	4.7	1.8	—	(17.1)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (a)	(4.7)	—	—	—	(4.7)
Purchased Electricity for Resale (a)	21.1	—	—	—	21.1
Interest Expense (a)	—	0.8	—	—	0.8
Amortization of Prior Service Cost (Credit)	—	—	—	(9.8)	(9.8)
Amortization of Actuarial (Gains)/Losses	—	—	—	10.6	10.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	16.4	0.8	—	0.8	18.0
Income Tax (Expense) Credit	5.7	0.2	—	0.3	6.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	10.7	0.6	—	0.5	11.8
Net Current Period Other Comprehensive Income (Loss)	(12.9)	5.3	1.8	0.5	(5.3)
Balance in AOCI as of June 30, 2017	$(36.0)	$(10.4)	$ 10.2	$(125.4)	$(161.6)

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AEP Texas

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2018	$ (5.2)	$ (9.8)	$(15.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.3	—	0.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.3	—	0.3
Income Tax (Expense) Credit	—	—	—
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 June 30, 2018	$ (4.9)	$ (9.8)	$(14.7)

AEP Texas

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2017	$ (5.2)	$ (9.4)	$(14.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.4	—	0.4
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.4	0.1	0.5
Income Tax (Expense) Credit	0.1	0.1	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 June 30, 2017	$ (4.9)	$ (9.4)	$(14.3)

AEP Texas

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ (8.1)	$(12.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.6	0.1	0.7
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.5	0.1	0.6
Net Current Period Other Comprehensive Income (Loss)	0.5	0.1	0.6
ASU 2018-02 Adoption (b)	(0.9)	(1.8)	(2.7)
Balance in AOCI as of June 30, 2018	$ (4.9)	$ (9.8)	$(14.7)

AEP Texas

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ (9.5)	$(14.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.7	—	0.7
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.7	0.2	0.9
Income Tax (Expense) Credit	0.2	0.1	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.5	0.1	0.6
Net Current Period Other Comprehensive Income (Loss)	0.5	0.1	0.6
Balance in AOCI as of June 30, 2017	$ (4.9)	$ (9.4)	$(14.3)

APCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2018	$2.5	$(1.9)	$0.6
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	(0.2)	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains)/Losses	—	0.3	0.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)	(1.0)	(1.2)
Income Tax (Expense) Credit	—	(0.2)	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.2)	(0.8)	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(0.2)	(0.8)	(1.0)
Balance in AOCI as of June 30, 2018	$2.3	$(2.7)	$(0.4)

APCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2017	$2.7	$(11.6)	$(8.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	(0.3)	—	(0.3)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains)/Losses	—	0.9	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.3)	(0.4)	(0.7)
Income Tax (Expense) Credit	(0.1)	(0.1)	(0.2)
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 June 30, 2017	$2.5	$(11.9)	$(9.4)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 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 (a)	0.9	—	—	0.9
Interest Expense (a)	—	(0.5)	—	(0.5)
Amortization of Prior Service Cost (Credit)	—	—	(2.6)	(2.6)
Amortization of Actuarial (Gains)/Losses	—	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.9	(0.5)	(2.0)	(1.6)
Income Tax (Expense) Credit	0.2	(0.1)	(0.4)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.7	(0.4)	(1.6)	(1.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.4)	(1.6)	(2.0)
ASU 2018-02 Adoption (b)	—	0.5	(0.2)	0.3
Balance in AOCI as of June 30, 2018	$ —	$ 2.3	$ (2.7)	$ (0.4)

APCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$ 2.9	$ (11.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	(0.6)	—	(0.6)
Amortization of Prior Service Cost (Credit)	—	(2.6)	(2.6)
Amortization of Actuarial (Gains)/Losses	—	1.7	1.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.6)	(0.9)	(1.5)
Income Tax (Expense) Credit	(0.2)	(0.3)	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.4)	(0.6)	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(0.4)	(0.6)	(1.0)
Balance in AOCI as of June 30, 2017	$ 2.5	$ (11.9)	$ (9.4)

I&M

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2018	$(12.7)	$(1.7)	$(14.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains)/Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.6	—	0.6
Income Tax (Expense) Credit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.5	—	0.5
Net Current Period Other Comprehensive Income (Loss)	0.5	—	0.5
Balance in AOCI as of June 30, 2018	$(12.2)	$(1.7)	$(13.9)

I&M

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2017	$(11.7)	$(4.2)	$(15.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(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
Balance in AOCI as of June 30, 2017	$(11.3)	$(4.2)	$(15.5)

I&M

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$(10.7)	$(1.4)	$(12.1)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.1	—	1.1
Amortization of Prior Service Cost (Credit)	—	(0.4)	(0.4)
Amortization of Actuarial (Gains)/Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.1	—	1.1
Income Tax (Expense) Credit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.9	—	0.9
Net Current Period Other Comprehensive Income (Loss)	0.9	—	0.9
ASU 2018-02 Adoption (b)	(2.4)	(0.3)	(2.7)
Balance in AOCI as of June 30, 2018	$(12.2)	$(1.7)	$(13.9)

I&M

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(12.0)	$(4.2)	$(16.2)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.4)	(0.4)
Amortization of Actuarial (Gains)/Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.0	—	1.0
Income Tax (Expense) Credit	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.7	—	0.7
Net Current Period Other Comprehensive Income (Loss)	0.7	—	0.7
Balance in AOCI as of June 30, 2017	$(11.3)	$(4.2)	$(15.5)

OPCo

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of March 31, 2018	$ 2.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
Balance in AOCI as of June 30, 2018	$ 1.7

OPCo

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of March 31, 2017	$ 2.8
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
Balance in AOCI as of June 30, 2017	$ 2.5

OPCo

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.8)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.6)
Net Current Period Other Comprehensive Income (Loss)	(0.6)
ASU 2018-02 Adoption (b)	0.4
Balance in AOCI as of June 30, 2018	$ 1.7

OPCo

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.8)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.8)
Income Tax (Expense) Credit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.5)
Net Current Period Other Comprehensive Income (Loss)	(0.5)
Balance in AOCI as of June 30, 2017	$ 2.5

PSO

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of March 31, 2018	$ 2.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.4)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.4)
Income Tax (Expense) Credit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.3)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
Balance in AOCI as of June 30, 2018	$ 2.6

PSO

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of March 31, 2017	$ 3.2
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(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 June 30, 2017	$ 3.0

PSO

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

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

PSO

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

	Cash Flow Hedge - Interest Rate (in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.6)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.6)
Income Tax (Expense) Credit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.4)
Net Current Period Other Comprehensive Income (Loss)	(0.4)
Balance in AOCI as of June 30, 2017	$ 3.0

SWEPCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2018	$(6.9)	$ 2.1	$(4.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.6	(0.5)	0.1
Income Tax (Expense) Credit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.5	(0.4)	0.1
Net Current Period Other Comprehensive Income (Loss)	0.5	(0.4)	0.1
Balance in AOCI as of June 30, 2018	$(6.4)	$ 1.7	$(4.7)

SWEPCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of March 31, 2017	$(6.9)	$ (2.2)	$(9.1)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains)/Losses	—	0.3	0.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	0.4	(0.2)	0.2
Income Tax (Expense) Credit	0.2	(0.1)	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.2	(0.1)	0.1
Net Current Period Other Comprehensive Income (Loss)	0.2	(0.1)	0.1
Balance in AOCI as of June 30, 2017	$(6.7)	$ (2.3)	$(9.0)

SWEPCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2017	$(6.0)	$ 2.0	$(4.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.1	—	1.1
Amortization of Prior Service Cost (Credit)	—	(1.0)	(1.0)
Amortization of Actuarial (Gains)/Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.1	(0.9)	0.2
Income Tax (Expense) Credit	0.2	(0.2)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.9	(0.7)	0.2
Net Current Period Other Comprehensive Income (Loss)	0.9	(0.7)	0.2
ASU 2018-02 Adoption (b)	(1.3)	0.4	(0.9)
Balance in AOCI as of June 30, 2018	$(6.4)	$ 1.7	$(4.7)

SWEPCo

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

	Cash Flow Hedge - Interest Rate	Pension and OPEB	Total
	(in millions)		
Balance in AOCI as of December 31, 2016	$(7.4)	$ (2.0)	$(9.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.1	—	1.1
Amortization of Prior Service Cost (Credit)	—	(1.0)	(1.0)
Amortization of Actuarial (Gains)/Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Credit	1.1	(0.5)	0.6
Income Tax (Expense) Credit	0.4	(0.2)	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	0.7	(0.3)	0.4
Net Current Period Other Comprehensive Income (Loss)	0.7	(0.3)	0.4
Balance in AOCI as of June 30, 2017	$(6.7)	$ (2.3)	$(9.0)

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

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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	
	June 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	16.3	9.6
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs (a)	146.0	128.0
Plant Retirement Costs - Asset Retirement Obligation Costs	39.7	39.7
Cook Plant Uprate Project	—	36.3
Cook Plant Turbine	—	15.9
Other Regulatory Assets Pending Final Regulatory Approval	17.8	42.2
Total Regulatory Assets Pending Final Regulatory Approval (b)	$270.1	$ 322.0

(a) As of June 30, 2018, AEP Texas has deferred $121 million related to Hurricane Harvey and will request securitization of the regulatory asset.

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

	AEP Texas	
	June 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	$ 144.5	$ 123.3
Rate Case Expense	0.2	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 144.7	$ 123.4

(a) As of June 30, 2018, AEP Texas has deferred $121 million related to Hurricane Harvey and will request securitization of the regulatory asset.

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

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

	I&M	
	June 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Uprate Project	$ —	$ 36.3
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	—	14.7
Cook Plant Turbine	—	15.9
Rockport Dry Sorbent Injection System - Indiana	—	10.4
Other Regulatory Assets Pending Final Regulatory Approval	3.3	2.0
Total Regulatory Assets Pending Final Regulatory Approval	$ 3.3	$ 79.3

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	PSO	
	June 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$—	$ 3.2
Other Regulatory Assets Pending Final Regulatory Approval	0.3	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$0.3	$ 3.3

	SWEPCo	
	June 30, 2018	December 31, 2017
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs - Unrecovered Plant	$50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	0.5	0.5
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation - Arkansas, Louisiana	4.7	4.0
Rate Case Expense - Texas	4.5	4.3
Shipe Road Transmission Project - FERC	—	3.3
Other Regulatory Assets Pending Final Regulatory Approval	3.0	2.5
Total Regulatory Assets Pending Final Regulatory Approval	$63.0	$ 64.9

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

Impact of Tax Reform

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

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

AEP Texas Interim Transmission and Distribution Rates

As of June 30, 2018, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2018, subject to review, are estimated to be $894 million. A base rate review could produce a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

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

May 1, 2019.

In June 2018, the PUCT approved a Stipulation and Settlement agreement to reduce AEP Texas' transmission rates by $24 million annually, beginning June 28, 2018, to reflect the lower federal income tax rate due to Tax Reform. The settlement agreement did not address the return of Excess ADIT benefits to customers.

In June 2018, AEP Texas also filed a Stipulation and Settlement agreement to amend its Distribution Cost Recovery Factor (DCRF) to reduce distribution rates by approximately $5 million. The settlement recognizes additional distribution capital additions made in 2017 and addresses the lower federal income tax rate and refunding property related Excess ADIT. New rates will be effective September 1, 2018.

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 June 30, 2018, the total balance of AEP Texas' deferred storm costs is approximately $145 million, inclusive of approximately $121 million of incremental storm expenses recorded as a regulatory asset related to Hurricane Harvey. As of June 30, 2018, AEP Texas has recorded approximately $199 million of capital expenditures related to Hurricane Harvey. Also, as of June 30, 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 will request securitization of the regulatory asset. The standard process for securitization of storm cost recovery in Texas requires two filings with the PUCT. Management expects that AEP Texas will make 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 incurred fuel expenses from the July 2018 over/under recovery calculation, (b) reduce APCo's base rates by $50 million annually commencing 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 seek approval from the Virginia SCC for energy efficiency programs with projected costs in the aggregate of at least $140 million over the 10-year period ending July 1, 2028 and (f) require APCo to construct and/or acquire solar generation facilities in Virginia, as approved by the Virginia SCC, of at least 200 MW of aggregate capacity by July 1, 2028. Triennial reviews are subject to an earnings test which provides that 70% of any over earnings would be refunded or may be reinvested in approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. The Virginia SCC's triennial review of 2017-2019 APCo earnings could reduce future net income and cash flows and impact financial condition.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase includes $32 million ($28 million related to APCo) due to increased annual depreciation rates and also reflects the impact of the reduction in the federal income tax rate due to Tax Reform. A hearing at the WVPSC is scheduled for November 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 June 30, 2018, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $815 million. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

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

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

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

2017 Indiana Base Rate Case

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

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

In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement in its entirety.

2017 Michigan Base Rate Case

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

In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenors' proposal for up to 10% of I&M's Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day, as well as the MPSC staff's recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a return on common equity of 9.8%. If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million 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 $50 million, effective April 2018 based on a 9.9% return on common equity. The MPSC also approved the ALJ's recommendation related to the capacity rate.

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

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. 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 of the Indiana jurisdictional ownership share of costs, including investment carrying costs, (d) depreciation of the SCR asset over 10 years and (e) recovery of these costs using an I&M Indiana rider.

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

KPCo Rate Matters (Applies to AEP)

2017 Kentucky Base Rate Case

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

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

February 2018, an intervenor filed for rehearing recommending that the reduced corporate federal income tax rate be reflected in lower purchased power expense related to the Rockport UPA.

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

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

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

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio Electric Security Plan Filings

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

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

In 2015 and 2016, the PUCO issued orders in this proceeding. As part of the issued orders, the PUCO approved (a) the DIR with modified 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 April 2017, the PUCO rejected all pending rehearing requests related to the OVEC PPA. In June 2017, intervenors filed appeals to the Supreme Court of Ohio stating that the PUCO's approval of the OVEC PPA was unlawful and does not provide customers with rate stability. In June of 2018, oral arguments were held before the Supreme Court of Ohio.

In November 2016, OPCo refiled its amended ESP extension application and supporting testimony, consistent with the terms of the modified and approved stipulation agreement and based upon a 2016 PUCO order. The amended filing proposed to extend the ESP through May 2024.

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

In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In May 2018, OPCo and various intervenors filed requests for rehearing with the PUCO. In June 2018, these requests for rehearing were approved to allow further consideration of the requests.

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 July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. SWEPCo intends to file a request for rehearing in the third quarter of 2018.

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

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

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

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

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 by the LPSC. In May 2018, LPSC staff filed testimony that the environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants is prudent. In July 2018, an ALJ recommended the LPSC approve a settlement agreement for the environmental control investment. An order is expected in the third quarter of 2018. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2018 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 increase included SWEPCo's jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

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

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could total approximately $550 million, excluding AFUDC. As of June 30, 2018, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of June 30, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $624 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 June 30, 2018, (b) is subject to review by the LPSC and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. See "2017 Louisiana Formula Rate Filing" and "2018 Louisiana Formula Rate Filing" disclosures above.

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

FERC Rate Matters

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

In June 2016, PJM transmission owners, including AEP's transmission owning subsidiaries within PJM, and various state commissions filed a settlement agreement at the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In July 2016, certain parties filed comments at the FERC contesting the settlement agreement. In May 2018, the FERC approved the contested settlement agreement. PJM implemented a transmission enhancement charge adjustment through the PJM OATT, which will be billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms and has recorded $169 million to Customer Accounts Receivable and $82 million to Deferred Charges and Other Noncurrent Assets, with offsets to Regulatory Liabilities and Deferred Investment Tax Credits.

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

In October 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC the settlement agreement: (a) establishes a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to the normalization method of accounting, ratably over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In April 2018, an ALJ accepted the interim settlement rates, which included the $50 million one-time refund that occurred in the second quarter of 2018. These interim rates are subject to refund or surcharge, with interest.

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

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

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

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

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

In June 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. 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 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 its power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. In November 2017, a FERC order set the matter for hearing and settlement procedures.

In May 2018, SWEPCo filed a settlement agreement with ETEC and NTEC at the FERC that resolves the issues of the complaint. If approved by the FERC, the settlement agreement: (a) reduces the base return on common equity from 11.1% to 10.1% effective September 1, 2017, (b) requires SWEPCo to provide a one-time billing credit of $287 thousand to reflect the decrease in return on common equity from September 1, 2017 through December 31, 2017, (c) implements the lower return on common equity on contracts starting January 1, 2018 and (d) allows SWEPCo to recover costs related to the Wind Catcher Project, as well as other concessions and guarantees. An order from the FERC is expected later this year.

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, AEP Texas and OPCo)

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

AEP has a $3 billion revolving credit facility due in June 2021, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of June 30, 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. The Registrants’ maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2018 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 80.3	August 2018 to June 2019
AEP Texas	2.8	January 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.

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

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $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 $78 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of June 30, 2018, SWEPCo has collected $73 million through a rider for final mine closure and reclamation costs, of which $78 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 June 30, 2018, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2018, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of June 30, 2018, the maximum potential loss by Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss

	(in millions)
AEP	$ 45.0
AEP Texas	10.9
APCo	8.8
I&M	3.2
OPCo	6.6
PSO	3.8
SWEPCo	3.9

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

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo have exercised all renewal options for the maximum lease term. The future minimum lease obligations were $7 million and $7 million for I&M and SWEPCo, respectively, for the remaining railcars as of June 30, 2018.

Under the remaining five-year lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which is equal to 77% of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee were $5 million and $5 million for I&M and SWEPCo, respectively, as of June 30, 2018, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. Certain of the boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2027. As of June 30, 2018, the maximum potential amount of future payments required under the guaranteed leases was $47 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 June 30, 2018, AEP’s boat and barge lease guarantee liability was $6 million, of which $1 million was recorded in Other Current Liabilities and $5 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP’s balance sheet.

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

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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

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

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

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

Westinghouse Electric Company Bankruptcy Filing

In March 2017, Westinghouse filed a petition to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Westinghouse and I&M have a number of significant ongoing contracts relating to reactor services, nuclear fuel fabrication and ongoing engineering projects. The most significant of these relate to Cook Plant fuel fabrication. As part of the reorganization, the bankruptcy court approved Westinghouse’s sale of its nuclear business to Brookfield WEC Holdings (Brookfield), a nonaffiliated third party. Pursuant to the sale, Brookfield will assume all of I&M’s contracts with Westinghouse. The sale is subject to regulatory approvals by the IURC and the MPSC 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 would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs’ claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. The court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. Plaintiffs voluntarily dismissed the surviving claims with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit on whether the trial court erred in dismissing plaintiffs’ claims for breach of contract and breach of the implied covenant of good faith and fair dealing.

In April 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion reversing the district court’s decisions in part. In June 2017, on rehearing, the court of appeals issued an amended opinion reversing the district court’s dismissal of certain of plaintiffs’ claims for breach of contract, vacating the denial of the plaintiffs’ motion for partial summary judgment and remanding the case to the district court for further proceedings. The amended opinion and judgment affirmed the district court’s dismissal of the owners’ breach of good faith and fair dealing claim as duplicative of the breach of contract claims and removed the instruction to the district court in the original opinion to enter summary judgment in favor of the owners.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. Responsive and supplemental filings have been made by all parties. The motion is fully briefed and remains pending before the court. 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. A settlement was reached with all of the plaintiffs and was approved by the WVMLP in June 2018. The settlement did not have a material impact on net income, cash flows or financial condition.

6. DISPOSITIONS AND IMPAIRMENTS

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

DISPOSITIONS

Zimmer Plant (Generation & Marketing Segment)

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

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

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

IMPAIRMENTS

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

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

Merchant Generating Assets (Generation & Marketing Segment)

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		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$24.4	$24.1	$2.9	$2.8
Interest Cost	47.0	50.8	11.9	14.9
Expected Return on Plan Assets	(72.6)	(71.2)	(25.6)	(25.4)
Amortization of Prior Service Cost (Credit)	—	0.2	(17.2)	(17.2)
Amortization of Net Actuarial Loss	21.3	20.7	2.6	9.1
Net Periodic Benefit Cost (Credit)	$20.1	$24.6	$(25.4)	$(15.8)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$48.8	$48.2	$5.8	$5.6
Interest Cost	93.9	101.6	23.7	29.7
Expected Return on Plan Assets	(145.1)	(142.4)	(51.1)	(50.7)
Amortization of Prior Service Cost (Credit)	—	0.5	(34.5)	(34.5)
Amortization of Net Actuarial Loss	42.6	41.4	5.2	18.3
Net Periodic Benefit Cost (Credit)	$40.2	$49.3	$(50.9)	$(31.6)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.2	$0.1	$0.2
Interest Cost	4.0	4.3	1.0	1.3
Expected Return on Plan Assets	(6.4)	(6.3)	(2.2)	(2.2)
Amortization of Prior Service Credit	—	—	(1.4)	(1.5)
Amortization of Net Actuarial Loss	1.8	1.7	0.2	0.8
Net Periodic Benefit Cost (Credit)	$1.7	$1.9	$(2.3)	$(1.4)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$4.6	$4.3	$0.4	$0.4
Interest Cost	8.0	8.6	1.9	2.5
Expected Return on Plan Assets	(12.8)	(12.6)	(4.3)	(4.4)
Amortization of Prior Service Credit	—	—	(2.9)	(2.9)
Amortization of Net Actuarial Loss	3.6	3.5	0.4	1.6
Net Periodic Benefit Cost (Credit)	$3.4	$3.8	$(4.5)	$(2.8)

APCo

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.4	$0.2	$0.2
Interest Cost	5.9	6.4	2.1	2.7
Expected Return on Plan Assets	(9.2)	(9.0)	(4.0)	(4.1)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.7	2.6	0.5	1.5
Net Periodic Benefit Cost (Credit)	$1.7	$2.4	$(3.7)	$(2.2)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	

	2018	2017	2018	2017
	(in millions)			
Service Cost	$4.6	$4.7	$0.5	$0.5
Interest Cost	11.8	12.8	4.1	5.3
Expected Return on Plan Assets	(18.3)	(17.9)	(8.0)	(8.2)
Amortization of Prior Service Cost (Credit)	—	0.1	(5.0)	(5.0)
Amortization of Net Actuarial Loss	5.3	5.2	1.0	3.1
Net Periodic Benefit Cost (Credit)	$3.4	$4.9	$(7.4)	$(4.3)

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I&M

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$3.4	$3.5	$0.4	$0.4
Interest Cost	5.5	6.0	1.3	1.8
Expected Return on Plan Assets	(8.9)	(8.7)	(3.1)	(3.0)
Amortization of Prior Service Cost (Credit)	—	0.1	(2.3)	(2.4)
Amortization of Net Actuarial Loss	2.4	2.5	0.3	1.1
Net Periodic Benefit Cost (Credit)	$2.4	$3.4	$(3.4)	$(2.1)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$6.8	$7.0	$0.8	$0.8
Interest Cost	11.0	12.1	2.7	3.5
Expected Return on Plan Assets	(17.8)	(17.3)	(6.2)	(6.1)
Amortization of Prior Service Cost (Credit)	—	0.1	(4.7)	(4.7)
Amortization of Net Actuarial Loss	4.9	4.9	0.6	2.2
Net Periodic Benefit Cost (Credit)	$4.9	$6.8	$(6.8)	$(4.3)

OPCo

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$1.8	$1.9	$0.3	$0.2
Interest Cost	4.5	4.9	1.3	1.7
Expected Return on Plan Assets	(7.2)	(7.0)	(2.9)	(3.0)
Amortization of Prior Service Cost (Credit)	—	0.1	(1.8)	(1.8)
Amortization of Net Actuarial Loss	2.0	1.9	0.2	1.1
Net Periodic Benefit Cost (Credit)	$1.1	$1.8	$(2.9)	$(1.8)

	Pension Plans		OPEB	
	Six Months Ended June		Six Months Ended June	

	30, 2018	2017	30, 2018	2017
	(in millions)			
Service Cost	$3.8	$3.8	$0.5	$0.4
Interest Cost	8.9	9.7	2.6	3.4
Expected Return on Plan Assets	(14.4)	(14.0)	(5.9)	(6.0)
Amortization of Prior Service Cost (Credit)	—	0.1	(3.5)	(3.5)
Amortization of Net Actuarial Loss	4.0	3.9	0.5	2.2
Net Periodic Benefit Cost (Credit)	$2.3	$3.5	$(5.8)	$(3.5)

PSO

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$1.8	$1.6	$0.2	$0.1
Interest Cost	2.5	2.7	0.6	0.8
Expected Return on Plan Assets	(4.1)	(4.0)	(1.4)	(1.4)
Amortization of Prior Service Credit	—	—	(1.1)	(1.0)
Amortization of Net Actuarial Loss	1.1	1.1	0.2	0.5
Net Periodic Benefit Cost (Credit)	$1.3	$1.4	$(1.5)	$(1.0)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$3.6	$3.2	$0.4	$0.3
Interest Cost	4.9	5.4	1.2	1.6
Expected Return on Plan Assets	(8.1)	(7.9)	(2.8)	(2.8)
Amortization of Prior Service Credit	—	—	(2.1)	(2.1)
Amortization of Net Actuarial Loss	2.2	2.2	0.3	1.0
Net Periodic Benefit Cost (Credit)	$2.6	$2.9	$(3.0)	$(2.0)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Service Cost	$2.3	$2.2	$0.2	$0.2
Interest Cost	2.8	3.0	0.7	0.9
Expected Return on Plan Assets	(4.3)	(4.2)	(1.6)	(1.6)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.2	1.2	0.2	0.6
Net Periodic Benefit Cost (Credit)	$2.0	$2.2	$(1.8)	$(1.2)

	Pension Plans		OPEB	
	Six Months Ended June 30,		Six Months Ended June 30,	

	2018	2017	2018	2017
	(in millions)			
Service Cost	$4.6	$4.4	$0.5	$0.4
Interest Cost	5.7	6.1	1.4	1.8
Expected Return on Plan Assets	(8.7)	(8.4)	(3.2)	(3.2)
Amortization of Prior Service Credit	—	—	(2.6)	(2.6)
Amortization of Net Actuarial Loss	2.5	2.4	0.3	1.2
Net Periodic Benefit Cost (Credit)	$4.1	$4.5	$(3.6)	$(2.4)

8. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

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

The tables below present AEP’s reportable segment income statement information for the three and six months ended June 30, 2018 and 2017 and reportable segment balance sheet information as of June 30, 2018 and December 31, 2017.

Three Months Ended June 30, 2018

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$2,340.7	$ 1,127.9	$ 103.5	$ 435.3	$ 5.8	$ —	$ 4,013.2
Other Operating Segments	8.3	9.1	109.0	25.4	18.0	(169.8)	—
Total Revenues	$2,349.0	$ 1,137.0	$ 212.5	$ 460.7	$ 23.8	$ (169.8)	$ 4,013.2
Net Income (Loss)	$277.9	$ 114.0	$ 101.9	$ 38.6	$ (2.3)	$ —	$ 530.1

Three Months Ended June 30, 2017

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$2,095.7	$ 1,026.6	$ 53.0	$ 386.5	$ 14.7	$ —	$ 3,576.5
Other Operating Segments	24.8	26.9	194.3	24.1	14.2	(284.3)	—
Total Revenues	$2,120.5	$ 1,053.5	$ 247.3	$ 410.6	$ 28.9	$ (284.3)	$ 3,576.5
Net Income (Loss)	$121.4	$ 111.2	$ 129.0	$ 26.4	$ (11.8)	$ —	$ 376.2

Six Months Ended June 30, 2018

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$4,722.2	$ 2,269.1	$ 144.6	$ 912.8	$ 12.8	$ —	$ 8,061.5
Other Operating Segments	34.8	30.3	273.4	53.0	35.0	(426.5)	—
Total Revenues	$4,757.0	$ 2,299.4	$ 418.0	$ 965.8	$ 47.8	$ (426.5)	$ 8,061.5
Net Income (Loss)	$510.7	$ 239.4	$ 206.7	$ 56.7	$ (26.7)	$ —	$ 986.8

Six Months Ended June 30, 2017

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$4,365.5	$ 2,093.0	$ 80.7	$ 945.3	$ 25.3	$ —	$ 7,509.8

Other Operating Segments	45.4	46.9	322.7	56.7	30.1	(501.8)	—
Total Revenues	$4,410.9	$ 2,139.9	$ 403.4	$ 1,002.0	$ 55.4	$ (501.8)	$ 7,509.8
Net Income (Loss)	$341.9	$ 230.3	$ 201.8	$ 212.6	$ (16.2)	$ —	$ 970.4

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	June 30, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$44,162.5	$ 17,208.3	$ 7,784.5	$ 829.8	$ 382.9	$ (355.1) (b)	$ 70,012.9
Accumulated Depreciation and Amortization	13,495.0	3,830.9	219.0	28.2	185.2	(186.9) (b)	17,571.4
Total Property Plant and Equipment - Net	$30,667.5	$ 13,377.4	$ 7,565.5	$ 801.6	$ 197.7	$ (168.2) (b)	$ 52,441.5
Total Assets	$38,422.6	$ 16,384.1	$ 8,666.4	$ 2,284.4	$4,071.8 (c)	$ (2,959.2) (b) (d)	$ 66,870.1
Long-term Debt Due Within One Year:							
Nonaffiliated	$1,890.8	$ 341.3	$ 50.0	$ 0.1	$ (0.8)	$ —	$ 2,281.4
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	10,455.9	5,390.2	2,640.5	(0.3)	1,264.3	—	19,750.6
Total Long-term Debt	$12,396.7	$ 5,731.5	$ 2,690.5	$ 32.0	$ 1,263.5	$ (82.2)	$ 22,032.0

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

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

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

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the three and six months ended June 30, 2018 and 2017 and reportable segment balance sheet information as of June 30, 2018 and December 31, 2017.

	Three Months Ended June 30, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$51.2	$ —	$ —	$ 51.2
Sales to AEP Affiliates	132.6	—	—	132.6
Other Revenues	—	—	—	—
Total Revenues	$183.8	$ —	$ —	$ 183.8
Interest Income	$—	$ 25.2	$ (24.8) (a)	$ 0.4
Interest Expense	20.3	24.8	(24.8) (a)	20.3
Income Tax Expense	19.4	0.6	—	20.0
Net Income	$70.8	$ (0.3) (b)	$ —	$ 70.5

	Three Months Ended June 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$44.0	$ —	$ —	$ 44.0
Sales to AEP Affiliates	185.5	—	(0.1)	185.4
Other Revenues	—	—	—	—
Total Revenues	$229.5	$ —	$ (0.1)	$ 229.4
Interest Income	$—	$ 19.4	$ (19.3) (a)	$ 0.1
Interest Expense	15.9	19.1	(19.3) (a)	15.7
Income Tax Expense	55.7	0.1	—	55.8
Net Income	$107.4	$ — (b)	$ —	$ 107.4

	Six Months Ended June 30, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$82.5	$ —	$ —	$ 82.5
Sales to AEP Affiliates	294.7	—	—	294.7
Other Revenues	0.1	$ —	$ —	0.1
Total Revenues	$377.3	$ —	$ —	$ 377.3
Interest Income	$0.2	$ 50.2	$ (49.6) (a)	$ 0.8
Interest Expense	40.2	49.6	(49.6) (a)	40.2
Income Tax Expense	41.7	0.8	—	42.5
Net Income	$156.8	$ (0.4) (b)	$ —	$ 156.4

	Six Months Ended June 30, 2017			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$63.2	$ —	$ —	$ 63.2
Sales to AEP Affiliates	318.9	—	(0.1)	318.8
Other Revenues	0.1	—	—	0.1
Total Revenues	$382.2	$ —	$ (0.1)	$ 382.1
Interest Income	$0.1	$ 38.5	$ (38.3) (a)	$ 0.3
Interest Expense	31.7	38.3	(38.3) (a)	31.7
Income Tax Expense	84.1	0.2	—	84.3
Net Income	$164.2	$ 0.2 (b)	$ —	$ 164.4

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	June 30, 2018					
	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Total Transmission Property	$7,426.4	$—		$ —		$ 7,426.4
Accumulated Depreciation and Amortization	210.5	—		—		210.5
Total Transmission Property – Net	$7,215.9	$—		$ —		$ 7,215.9
Notes Receivable - Affiliated	$—	$2,575.0		$ (2,575.0)	(c)	$ —
Total Assets	$7,533.4	$2,623.4	(d)	$ (2,622.1)	(e)	$ 7,534.7
Total Long-term Debt	$2,575.0	$2,550.9		$ (2,575.0)	(c)	$ 2,550.9

	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.

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments
June 30, 2018

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
		(in millions)						
Commodity:								
Power	MWhs	480.2	—	113.2	62.3	8.1	28.6	20.0
Coal	Tons	0.4	—	—	0.4	—	—	—
Natural Gas	MMBtus	69.1	—	3.7	2.1	—	—	17.0
Heating Oil and Gasoline	Gallons	7.2	1.5	1.4	0.7	1.7	0.7	0.8
Interest Rate	USD	$43.0	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$500.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2017

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

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

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

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for “Derivatives and Hedging,” the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. AEP netted cash collateral received from third parties against short-term and long-term risk management assets in the amounts of $7 million and $9.4 million as of June 30, 2018 and December 31, 2017, respectively. AEP netted cash collateral paid to third parties against short-term and long-term risk management liabilities in the amounts of $3 million and $9 million as of June 30, 2018 and December 31, 2017, respectively. The netted cash collateral from third parties against short-term and long-term risk management assets and netted cash collateral paid to third parties against short-term and long-term risk management liabilities were immaterial for the other Registrants as of June 30, 2018 and December 31, 2017.

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

AEP

Fair Value of Derivative Instruments
June 30, 2018

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$ 343.5	$ 23.1	$ —	$ 366.6	$ (172.0)	$ 194.6
Long-term Risk Management Assets	305.3	6.4	—	311.7	(47.2)	264.5
Total Assets	648.8	29.5	—	678.3	(219.2)	459.1
Current Risk Management Liabilities	213.3	7.5	0.7	221.5	(167.5)	54.0
Long-term Risk Management Liabilities	245.0	55.8	27.2	328.0	(48.4)	279.6
Total Liabilities	458.3	63.3	27.9	549.5	(215.9)	333.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 190.5	$ (33.8)	$ (27.9)	$ 128.8	$ (3.3)	$ 125.5

Fair Value of Derivative Instruments
December 31, 2017

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

Total MTM Derivative Contract Net Assets (Liabilities)	$74.7	$(43.5)	$(6.1)	$ 25.1	$(0.4)	$ 24.7

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AEP Texas
Fair Value of Derivative Instruments
June 30, 2018

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

Fair Value of Derivative Instruments
December 31, 2017

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

APCo
Fair Value of Derivative Instruments
June 30, 2018
Balance Sheet Location

	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$95.0	$ (34.6)	$ 60.4
Long-term Risk Management Assets	9.4	(7.3)	2.1
Total Assets	104.4	(41.9)	62.5
Current Risk Management Liabilities	35.3	(33.9)	1.4
Long-term Risk Management Liabilities	7.7	(7.2)	0.5
Total Liabilities	43.0	(41.1)	1.9
Total MTM Derivative Contract Net Assets (Liabilities)	$61.4	$ (0.8)	$ 60.6

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
June 30, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$38.1	$ (23.7)	$ 14.4
Long-term Risk Management Assets	5.6	(4.4)	1.2
Total Assets	43.7	(28.1)	15.6
Current Risk Management Liabilities	28.8	(23.4)	5.4
Long-term Risk Management Liabilities	4.5	(4.2)	0.3
Total Liabilities	33.3	(27.6)	5.7
Total MTM Derivative Contract Net Assets (Liabilities)	$10.4	$ (0.5)	$ 9.9

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	$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
June 30, 2018
Balance Sheet Location

	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$0.5	$ (0.1)	$ 0.4
Long-term Risk Management Assets	0.1	—	0.1
Total Assets	0.6	(0.1)	0.5
Current Risk Management Liabilities	4.8	—	4.8
Long-term Risk Management Liabilities	82.0	—	82.0
Total Liabilities	86.8	—	86.8
Total MTM Derivative Contract Net Liabilities	$(86.2)	$ (0.1)	$ (86.3)

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	$0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6
Current Risk Management Liabilities	6.4	—	6.4
Long-term Risk Management Liabilities	126.0	—	126.0
Total Liabilities	132.4	—	132.4
Total MTM Derivative Contract Net Liabilities	$(131.8)	$ —	$ (131.8)

PSO
Fair Value of Derivative Instruments
June 30, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$24.9	$ (0.4)	$ 24.5
Long-term Risk Management Assets	—	—	—
Total Assets	24.9	(0.4)	24.5
Current Risk Management Liabilities	0.3	(0.3)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.3	(0.3)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$24.6	$ (0.1)	$ 24.5

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$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
June 30, 2018
Balance Sheet Location

	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Current Risk Management Assets	$9.8	$ (2.4)	$ 7.4
Long-term Risk Management Assets	—	—	—
Total Assets	9.8	(2.4)	7.4
Current Risk Management Liabilities	2.3	(2.3)	—
Long-term Risk Management Liabilities	2.3	—	2.3
Total Liabilities	4.6	(2.3)	2.3
Total MTM Derivative Contract Net Assets (Liabilities)	$5.2	$ (0.1)	$ 5.1

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) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

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

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended June 30, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$(3.2)	$ —	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	27.5	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.5)	(2.6)	—	—	0.1
Purchased Electricity for Resale	3.1	—	2.4	0.6	—	—	—
Other Operation	0.5	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.5	0.1	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	5.9	—	—	(3.0)	9.7	—	(0.8)
Regulatory Liabilities (a)	85.4	0.1	39.2	11.5	0.6	18.8	6.9
Total Gain on Risk Management Contracts	$119.7	$ 0.3	$41.3	$6.7	$10.5	$19.0	$ 6.4

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

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$0.6	$—	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	10.3	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.1)	0.5	—	—	—
Purchased Electricity for Resale	1.5	—	0.5	0.2	—	—	—
Other Operation	0.2	—	—	—	—	—	—
Maintenance	0.1	—	—	—	—	—	—
Regulatory Assets (a)	(3.1)	(0.1)	5.7	—	(8.6)	—	—
Regulatory Liabilities (a)	41.0	(0.1)	13.6	6.4	—	8.7	10.4
Total Gain (Loss) on Risk Management Contracts	$50.6	$(0.2)	$19.7	$7.1	$(8.6)	$8.7	$ 10.4

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Six Months Ended June 30, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$(8.7)	$ —	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	12.4	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.8)	(7.7)	—	—	0.1
Purchased Electricity for Resale	8.0	—	7.0	0.8	—	—	—
Other Operation	0.8	0.2	0.1	0.1	0.2	0.1	0.1
Maintenance	0.9	0.2	0.2	0.1	0.2	0.1	0.1
Regulatory Assets (a)	43.2	—	—	3.2	41.1	—	(1.1)
Regulatory Liabilities (a)	172.4	—	103.3	11.7	0.6	30.9	6.1
Total Gain on Risk Management Contracts	$229.0	$ 0.4	$109.8	$8.2	$42.1	$31.1	$ 5.3

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

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$6.1	$—	$—	$—	$—	$—	$ —
Generation & Marketing Revenues	20.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.3	5.7	—	—	0.1
Purchased Electricity for Resale	3.9	—	1.3	0.3	—	—	—
Other Operation	0.4	—	—	—	—	—	—
Maintenance	0.3	—	—	—	—	—	—
Regulatory Assets (a)	(18.0)	(0.1)	(0.1)	(0.2)	(17.2)	—	(0.2)
Regulatory Liabilities (a)	66.2	(0.3)	24.5	13.2	—	11.1	15.0
Total Gain (Loss) on Risk Management Contracts	$79.7	$(0.4)	$26.0	$19.0	$(17.2)	$11.1	$ 14.9

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

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

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

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

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

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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

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

The following table shows the impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Assets/(Liabilities)		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Assets/(Liabilities)	
	June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
	(in millions)			
Long-Term Debt (a)	$(467.5)	$(489.3)	$ 27.9	$ 6.1

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.

The pretax effects of fair value hedge accounting on income were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Gain (Loss) on Fair Value Hedging Relationships				
Interest Rate Contracts:				
Gain (Loss) on Fair Value Hedging Instruments (a)	$(7.3)	$0.4	$(21.8)	$(0.1)
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	7.3	(0.4)	21.8	0.1

(a) Gain (Loss) is recorded on the statements of income within Interest Expense.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2018 and 2017, AEP applied cash flow hedging to outstanding power derivatives. During the three and six months ended June 30, 2018 and 2017, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2017, AEP applied cash flow hedging to outstanding interest rate derivatives. During the three and six months ended June 30, 2018, AEP did not apply cash flow hedging to outstanding interest rate derivatives. During the three and six months ended June 30, 2018 and 2017, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and six months ended June 30, 2018 and 2017, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

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

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

Impact of Cash Flow Hedges on AEP's Balance Sheets

	June 30, 2018		December 31, 2017	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Loss Net of Tax	$(30.4)	$(15.3)	$(28.4)	$(13.0)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	8.6	(1.0)	5.5	(0.8)

As of June 30, 2018 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 114 months.

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

	June 30, 2018		December 31, 2017	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$(4.9)	$ (1.1)	$(4.5)	$ (0.9)
APCo	2.3	0.9	2.2	0.7
I&M	(12.2)	(1.6)	(10.7)	(1.3)
OPCo	1.7	1.3	1.9	1.1
PSO	2.6	1.0	2.6	0.8
SWEPCo	(6.4)	(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 June 30, 2018 and December 31, 2017, respectively.

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

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

	June 30, 2018		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
	(in millions)		
AEP	$ 266.4	$ 2.8	$ 216.2
APCo	0.2	—	0.1
I&M	0.1	—	—

SWEPCo	2.3	—	2.3

	December 31, 2017		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
	(in millions)		
AEP	$243.6	$ 1.3	$ 223.1
APCo	0.6	—	0.5
I&M	0.4	—	0.4
SWEPCo	0.2	—	0.1

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

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

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

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

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

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

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

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

Company	June 30, 2018 Book Value	June 30, 2018 Fair Value	December 31, 2017 Book Value	December 31, 2017 Fair Value
	(in millions)			
AEP	$22,032.0	$23,320.6	$21,173.3	$23,649.6
AEP Texas	3,991.3	4,148.5	3,649.3	3,964.8
AEPTCo	2,550.9	2,586.3	2,550.4	2,782.9
APCo	4,073.7	4,593.9	3,980.1	4,782.6
I&M	3,096.8	3,234.6	2,745.1	3,014.7
OPCo	1,740.0	2,000.0	1,719.3	2,064.3
PSO	1,286.8	1,390.9	1,286.5	1,457.1
SWEPCo	2,503.7	2,543.7	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:

	June 30, 2018			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$198.7	$ —	$ —	$198.7
Fixed Income Securities – Mutual Funds (b)	105.4	—	(2.4)	103.0
Equity Securities – Mutual Funds	17.4	20.1	—	37.5
Total Other Temporary Investments	$321.5	$ 20.1	$ (2.4)	$339.2

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Proceeds from Investment Sales	$ —	$ —	$ —	$ —
Purchases of Investments	0.8	0.5	1.4	1.0
Gross Realized Gains on Investment Sales	—	—	—	—
Gross Realized Losses on Investment Sales	—	—	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the three and six months ended June 30, 2017, see Note 3 - Comprehensive Income.

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

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and 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:

	June 30, 2018			December 31, 2017		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$21.8	$ —	$ —	$17.2	$ —	$ —
Fixed Income Securities:						
United States Government	958.4	19.3	(6.0)	981.2	29.7	(3.6)
Corporate Debt	53.8	1.4	(1.8)	58.7	3.8	(1.2)
State and Local Government	26.6	0.6	(0.2)	8.8	0.8	(0.2)
Subtotal Fixed Income Securities	1,038.8	21.3	(8.0)	1,048.7	34.3	(5.0)
Equity Securities - Domestic (a)	1,494.3	882.9	—	1,461.7	868.2	(75.5)
Spent Nuclear Fuel and Decommissioning Trusts	$2,554.9	$ 904.2	$ (8.0)	$2,527.6	$ 902.5	$ (80.5)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $887.4 million and unrealized losses of $4.5 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in millions)			
Proceeds from Investment Sales	$529.2	$801.2	$1,037.8	$1,289.1
Purchases of Investments	542.5	811.7	1,067.8	1,317.2
Gross Realized Gains on Investment Sales	11.8	177.0	23.8	188.3
Gross Realized Losses on Investment Sales	7.8	132.1	18.7	140.2

The base cost of fixed income securities was $1 billion and $1 billion as of June 30, 2018 and December 31, 2017, respectively. The base cost of equity securities was $611 million and $594 million as of June 30, 2018 and December 31, 2017, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2018 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 353.1
After 1 year through 5 years	335.4
After 5 years through 10 years	168.3
After 10 years	182.0
Total	$ 1,038.8

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Fair Value Measurements of Financial Assets and Liabilities

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

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$161.2	$26.5	$—	$11.0	$198.7
Fixed Income Securities – Mutual Funds	103.0	—	—	—	103.0
Equity Securities – Mutual Funds (b)	37.5	—	—	—	37.5
Total Other Temporary Investments	301.7	26.5	—	11.0	339.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	1.4	259.4	362.2	(191.2)	431.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	18.2	6.3	2.8	27.3
Total Risk Management Assets	1.4	277.6	368.5	(188.4)	459.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.1	—	—	7.7	21.8
Fixed Income Securities:					
United States Government	—	958.4	—	—	958.4
Corporate Debt	—	53.8	—	—	53.8
State and Local Government	—	26.6	—	—	26.6
Subtotal Fixed Income Securities	—	1,038.8	—	—	1,038.8
Equity Securities – Domestic (b)	1,494.3	—	—	—	1,494.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,508.4	1,038.8	—	7.7	2,554.9
Total Assets	$1,811.5	$1,342.9	$368.5	$(169.7)	$3,353.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$1.1	$269.0	$162.4	$(187.9)	$244.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.5	33.8	2.8	61.1
Fair Value Hedges	—	27.9	—	—	27.9

Total Risk Management Liabilities	$1.1	$321.4	$196.2	$(185.1)	$333.6

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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
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$131.9	$—	$—	$—	$131.9
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.6	—	(0.1)	0.5
Total Assets	$131.9	$0.6	$—	$(0.1)	$132.4

AEP Texas

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

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

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$17.7	$—	$—	$—	$17.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	0.2	37.7	61.0	(36.4)	62.5
Total Assets	$17.9	$37.7	$61.0	$(36.4)	$80.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$36.5	$1.0	$(35.6)	$1.9

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
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$0.1	$24.1	$15.6	$(24.2)	$15.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.1	—	—	7.7	21.8
Fixed Income Securities:					
United States Government	—	958.4	—	—	958.4
Corporate Debt	—	53.8	—	—	53.8
State and Local Government	—	26.6	—	—	26.6
Subtotal Fixed Income Securities	—	1,038.8	—	—	1,038.8
Equity Securities - Domestic (b)	1,494.3	—	—	—	1,494.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,508.4	1,038.8	—	7.7	2,554.9
Total Assets	$1,508.5	$1,062.9	$15.6	$(16.5)	$2,570.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$27.0	$2.4	$(23.7)	$5.7

I&M

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$39.4	$9.1	$(40.2)	$8.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities - Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6

Total Assets	$1,469.2	$1,088.1	$9.1	$(30.5)	$2,535.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$47.6	$1.5	$(45.5)	$3.6

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OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$—	$26.5	$—	$—	$26.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.7	—	(0.2)	0.5
Total Assets	$—	$27.2	$—	$(0.2)	$27.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$86.9	$(0.1)	$86.8

OPCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.6	$—	$—	$0.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$132.4	$—	$132.4

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.3	$24.6	$(0.4)	$24.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$0.3	$(0.3)	$—

PSO

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$—	$0.2	$6.4	$(0.2)	$6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$—	$—	$0.2	$(0.2)	$—

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 9.5	$ (2.4)	$ 7.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 4.6	$ (2.3)	$ 2.3

SWEPCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 6.7	$ (0.6)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.8	$ (0.6)	$ 0.2

(a) Amounts in "Other'' column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other'' column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging.''

(d) The June 30, 2018 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(5) million in 2018 and $(7) million in periods 2019-2021 and $3 million in periods 2022-2023; Level 3 matures $77 million in 2018, $97 million in periods 2019-2021, $22 million in periods 2022-2023 and $3 million in periods 2024-2032. Risk management commodity contracts are substantially comprised of power contracts.

(e) Amounts in "Other'' column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

(f) The December 31, 2017 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(1) million in 2018; Level 2 matures $(3) million in 2018 and $2 million in periods 2022-2023; Level 3 matures $59 million in 2018, $33 million in periods 2019-2021, $14 million in periods 2022-2023 and $(29) million in periods 2024-2032. Risk management commodity contracts are

substantially comprised of power contracts.
(g) Substantially comprised of power contracts for the Registrant Subsidiaries.

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2018 and 2017.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Three Months Ended June 30, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of March 31, 2018	$62.0	$9.1	$2.9	$(98.5)	$2.8	$ 0.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	55.0	36.0	11.8	0.2	6.1	(4.0)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	5.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(10.3)	—	—	—	—	—
Settlements	(75.8)	(43.2)	(14.6)	1.3	(8.9)	2.6
Transfers into Level 3 (c) (d)	12.6	—	—	—	—	—
Transfers out of Level 3 (d)	0.4	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	122.5	58.1	13.1	10.1	24.3	5.4
Balance as of June 30, 2018	$172.3	$60.0	$13.2	$(86.9)	$24.3	$ 4.9

Three Months Ended June 30, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of March 31, 2017	$(18.5)	$(5.8)	$2.0	$(124.6)	$0.4	$ 0.5
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	17.1	12.2	0.6	(0.1)	0.8	1.4
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	8.7	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	12.1	—	—	—	—	—
Settlements	(16.1)	(6.4)	(2.7)	1.9	(1.3)	(1.9)
Transfers into Level 3 (c) (d)	6.2	—	—	—	—	—
Transfers out of Level 3 (d)	(1.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	78.9	41.3	15.6	(7.7)	9.6	12.4
Balance as of June 30, 2017	$87.3	$41.3	$15.5	$(130.5)	$9.5	$ 12.4

Six Months Ended June 30, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2017	$40.3	$24.7	$7.6	$(132.4)	$6.2	$ 5.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	152.6	104.7	15.1	0.9	18.1	(4.8)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	8.0	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	7.6	—	—	—	—	—
Settlements	(204.6)	(128.4)	(22.1)	2.5	(24.3)	(1.3)
Transfers into Level 3 (c) (d)	14.7	—	—	—	—	—
Transfers out of Level 3 (d)	(1.5)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	155.2	59.0	12.9	42.1	24.3	5.1
Balance as of June 30, 2018	$172.3	$60.0	$13.2	$(86.9)	$24.3	$ 4.9

Six Months Ended June 30, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2016	$2.5	$1.4	$2.8	$(119.0)	$0.7	$ 0.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	32.0	16.9	3.9	(4.3)	3.1	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	25.2	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(5.1)	—	—	—	—	—
Settlements	(44.3)	(18.6)	(6.9)	4.1	(3.8)	(6.8)
Transfers into Level 3 (c) (d)	10.7	—	—	—	—	—
Transfers out of Level 3 (d)	(9.4)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	75.7	41.6	15.7	(11.3)	9.5	12.5
Balance as of June 30, 2017	$87.3	$41.3	$15.5	$(130.5)	$9.5	$ 12.4

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents existing assets or liabilities that were previously categorized as Level 2.
(d) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(e) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets or accounts payable.

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

Significant Unobservable Inputs
June 30, 2018
AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$240.8	$ 187.1	Discounted Cash Flow	Forward Market Price (a)	$5.28	$145.99	$ 34.31
				Counterparty Credit Risk (b)	13	442	173
Natural Gas Contracts	—	2.3	Discounted Cash Flow	Forward Market Price (c)	2.22	2.88	2.49
FTRs	127.7	6.8	Discounted Cash Flow	Forward Market Price (a)	(9.40)	10.30	0.52
Total	$368.5	$ 196.2					

Significant Unobservable Inputs
December 31, 2017
AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$225.1	$ 233.7	Discounted Cash Flow	Forward Market Price (a)	$(0.05)	$263.00	$ 36.32
				Counterparty Credit Risk (b)	8	456	180
Natural Gas Contracts	—	0.2	Discounted Cash Flow	Forward Market Price (c)	2.37	2.96	2.62
FTRs	53.7	4.6	Discounted Cash Flow	Forward Market Price (a)	(55.62)	54.88	0.41
Total	$278.8	$ 238.5					

Significant Unobservable Inputs
June 30, 2018
APCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$1.5	$ 0.5	Discounted Cash Flow	Forward Market Price	$14.72	$63.75	$ 34.64
FTRs	59.5	0.5	Discounted Cash Flow	Forward Market Price	0.01	8.30	1.57
Total	$61.0	$ 1.0					

Significant Unobservable Inputs
December 31, 2017
APCo

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$0.8	$ 0.4	Discounted Cash Flow	Forward Market Price	$20.52	$195.00	$ 33.80
FTRs	24.3	—	Discounted Cash Flow	Forward Market Price	(0.36)	7.15	1.62
Total	$25.1	$ 0.4					

Significant Unobservable Inputs
June 30, 2018
I&M

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$0.3	$ 0.5	Discounted Cash Flow	Forward Market Price	$14.72	$63.75	$ 34.64
FTRs	15.3	1.9	Discounted Cash Flow	Forward Market Price	(1.50)	5.97	0.77
Total	$15.6	$ 2.4					

Significant Unobservable Inputs
December 31, 2017
I&M

	Fair Value		Valuation	Significant	Input/Range		
				Unobservable			Weighted
	Assets	Liabilities	Technique	Input (a)	Low	High	Average
	(in millions)						
Energy Contracts	$0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$20.52	$195.00	$ 33.80
FTRs	8.6	1.2	Discounted Cash Flow	Forward Market Price	(0.36)	5.75	0.86
Total	$9.1	$ 1.5					

Significant Unobservable Inputs
June 30, 2018
OPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 86.9	Discounted Cash Flow	Forward Market Price (a)	$ 31.56	$ 73.69	$ 47.11
				Counterparty Credit Risk (b)	13	197	151
Total	$ —	$ 86.9					

Significant Unobservable Inputs
December 31, 2017
OPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 132.4	Discounted Cash Flow	Forward Market Price (a)	$ 30.52	$ 170.43	$ 44.62
				Counterparty Credit Risk (b)	8	190	136
Total	$ —	$ 132.4					

Significant Unobservable Inputs
June 30, 2018
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 24.6	$ 0.3	Discounted Cash Flow	Forward Market Price	$ (9.40)	$ 10.30	$ (1.23)

Significant Unobservable Inputs
December 31, 2017
PSO

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 6.4	$ 0.2	Discounted Cash Flow	Forward Market Price	$ (6.62)	$ 1.41	$ (0.76)

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Significant Unobservable Inputs
June 30, 2018
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$—	$ 2.3	Discounted Cash Flow	Forward Market Price (c)	$2.22	$2.88	$ 2.49
FTRs	9.5	2.3	Discounted Cash Flow	Forward Market Price (a)	(9.40)	10.30	(1.23)
Total	$9.5	$ 4.6					

Significant Unobservable Inputs
December 31, 2017
SWEPCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$—	$ 0.2	Discounted Cash Flow	Forward Market Price (c)	$2.37	$2.96	$ 2.62
FTRs	6.7	0.6	Discounted Cash Flow	Forward Market Price (a)	(6.62)	1.41	(0.76)
Total	$6.7	$ 0.8					

(a) Represents market prices in dollars per MWh.
(b) Represents prices of credit default swaps used to calculate counterparty credit risk, reported in basis points.
(c) Represents market prices in dollars per MMBtu.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of June 30, 2018 and December 31, 2017:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)
Counterparty Credit Risk	Loss	Increase (Decrease)	Higher (Lower)
Counterparty Credit Risk	Gain	Increase (Decrease)	Lower (Higher)

11. INCOME TAXES

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

Federal Tax Reform

In December 2017, 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.

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. SAB 118 provides for up to a one year period to complete the required analysis and accounting for Tax Reform referred to as the measurement period. 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 measurement period adjustments recorded during the second quarter of 2018 to the provisional amounts were immaterial. The Registrants expect to complete the analysis of the provisional items during the second half of 2018.

Status of Tax Reform Regulatory Proceedings

The table below summarizes the current status of Tax Reform in AEP's various regulatory jurisdictions. For additional details on regulatory filings in these jurisdictions, see Note 4 - Rate Matters.

Registrant (Jurisdiction)	Change in Tax Rate	Excess ADIT Subject to Normalization Requirements	Excess ADIT Not Subject to Normalization Requirements
AEP Texas (Texas-Distribution)	Case Pending	Case Pending	Case Pending
AEP Texas (Texas-Transmission)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
APCo (Virginia)	Legislation Enacted	Legislation Enacted	To be addressed in a later filing
APCo (West Virginia)	Case Pending	Case Pending	Case Pending
I&M (Indiana)	Order Issued	Order Issued	Order Issued
I&M (Michigan)	Case Pending	To be addressed in a later filing	To be addressed in a later filing
AEP (Tennessee)	Case Pending	Case Pending	Case Pending
AEP (Kentucky)	Order Issued	Order Issued	Order Issued
OPCo (Ohio)	Case Pending	Case Pending	Case Pending
PSO (Oklahoma)	Order Issued	Case Pending	Case Pending
SWEPCo (Arkansas)	Case Pending	Case Pending	Case Pending
SWEPCo (Louisiana)	Case Pending	To be addressed in a later filing	To be addressed in a later filing
SWEPCo (Texas)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
PJM FERC Transmission	Settlement Approved	Settlement Approved	Settlement Approved

SPP FERC Transmission	To be addressed in a later filing	To be addressed in a later filing	To be addressed in a later filing

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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. The table below provides a summary of the estimated provisions for revenue refund recorded by the Registrants related to the reduction in the corporate federal tax rate as of June 30, 2018:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Increase in Current Liabilities	$ —	$ —	$ —	$ —	$ 4.0	$ —	$ —	$ —
Increase in Deferred Credits and Other Noncurrent Liabilities	143.6	18.0	5.7	48.8	10.3	27.8	4.7	24.2

Excess ADIT - Pending Rate Reductions

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

As reflected in the Registrants' respective estimated annual ETR for 2018, AEP's regulated public utilities began amortizing the Excess ADIT associated with certain depreciable property subject to rate normalization requirements using the ARAM during the first quarter of 2018. The amortization resulted in a reduction in the Excess ADIT balance recorded in Regulatory Liabilities and Deferred Investment Tax Credits and a reduction in Income Tax Expense. As a result of state utility commission orders or instructions, in the second quarter of 2018 the Registrants recorded estimated provisions for revenue refund offsetting the amortization of the Excess ADIT as shown in the table below:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Decrease in Total Revenues	$(33.3)	$(4.9)	$ (0.2)	$(9.6)	$(1.2)	$(2.5)	$(4.6)	$ (7.0)
Increase in Current Liabilities	1.2	—	—	0.4	0.3	0.3	—	—
Increase in Deferred Credits and Other Noncurrent Liabilities	32.1	4.9	0.2	9.2	0.9	2.2	4.6	7.0

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. As a result of certain state utility commission orders or instructions received and a filed FERC settlement agreement, AEP, AEPTCo, APCo, I&M, and OPCo began amortizing Excess ADIT not subject to rate normalization requirements.

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2018 and 2017, adjusted for tax expense associated with certain discrete items. As previously mentioned, effective January 1, 2018, Tax Reform lowered the corporate tax rate from 35% to 21%. The interim ETR differ from the federal statutory tax rate of 21% and 35% in 2018 and 2017, respectively, primarily due to state income taxes, the amortization of the Excess ADIT, tax credits and other book/tax differences which are accounted for on a flow-through basis.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2018	2017	2018	2017
AEP	12.0%	34.6%	15.0%	36.5%
AEP Texas	16.2%	34.6%	16.2%	34.6%
AEPTCo	22.1%	34.2%	21.4%	33.9%
APCo	17.0%	36.5%	17.8%	36.5%
I&M	0.7 %	27.6%	7.6 %	29.6%
OPCo	21.6%	34.9%	21.0%	34.9%
PSO	14.9%	37.6%	14.5%	37.6%
SWEPCo	12.4%	29.7%	14.0%	32.4%

AEP

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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, increased 2018 amortization of Excess ADIT and the discrete impact of state tax legislation enacted in Kentucky in April 2018.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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, increased 2018 amortization of Excess ADIT and the discrete impact of state tax legislation enacted in Kentucky in April 2018.

AEP Texas

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT.

AEPTCo

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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.

APCo

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT associated with certain depreciable property using the ARAM.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT associated with certain depreciable property using the ARAM.

I&M

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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, increased 2018 amortization of Excess ADIT and decreased state income taxes resulting from elimination of bonus depreciation for certain property acquired after September 27, 2017. These decreases were partially offset by an increase in book/tax differences which are accounted for on a flow-through basis resulting from a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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, increased 2018 amortization of Excess ADIT and decreased state income taxes resulting from elimination of bonus depreciation for certain property acquired after September 27, 2017. These decreases were partially offset by an increase in book/tax differences which are accounted for on a flow-through basis resulting from a change in the expected retirement date for Rockport Plant, Unit 1 from 2044 to 2028.

OPCo

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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.

PSO

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT associated with certain depreciable property using the ARAM.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT associated with certain depreciable property using the ARAM.

SWEPCo

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT associated with certain depreciable property using the ARAM.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The decrease in the ETR was 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 increased 2018 amortization of Excess ADIT associated with certain depreciable property using the ARAM.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011 through 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. To resolve the issue under consideration, AEP and subsidiaries and the IRS exam team agreed to utilize the Fast Track Settlement Program in December 2017. The program was completed in March 2018 and tax years 2014 and 2015 were added to the IRS examination to reflect the impact of the Fast Track changes that were carried forward to 2014 and 2015. In June 2018, AEP settled all outstanding issues under audit for tax years 2011-2015. As a result, the related $72 million unrecognized tax benefit was reversed in the second quarter of 2018. The settlement did not materially impact the Registrants net income, cash flows or financial condition.

AEP and subsidiaries file income tax returns in various state, local or foreign jurisdictions. These taxing authorities routinely examine the tax returns. AEP and subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. The Registrants are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

State Tax Legislation (Applies to AEP, AEPTCo, I&M and OPCo)

In April 2018, the Kentucky legislature enacted House Bill (H.B.) 487. H.B. 487 adopts mandatory unitary combined reporting for state corporate income tax purposes applicable for taxable years beginning on or after January 1, 2019. H.B. 487 also adopts the 80% federal net operating loss (NOL) limitation under Internal Revenue Code Sec. 172(a) for NOLs generated after January 1, 2018 and the federal unlimited carryforward period for unused NOLs generated after January 1, 2018. In addition, H.B. 366 was also enacted in April 2018, which among other things, replaces the graduated corporate tax rate structure with a flat 5% tax rate for business income and adopts a single-sales factor apportionment formula for apportioning a corporation's business income to Kentucky. In the second quarter of 2018, AEP recorded an $18 million benefit to Income Tax Expense as a result of remeasuring Kentucky deferred taxes under a unitary filing group. The enacted legislation did not materially impact AEPTCo's, I&M's or OPCo's net income.

12. FINANCING ACTIVITIES

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

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding:

Type of Debt	June 30, 2018	December 31, 2017
	(in millions)	
Senior Unsecured Notes	$17,461.1	$ 16,478.3
Pollution Control Bonds	1,643.4	1,621.7
Notes Payable	263.2	260.8
Securitization Bonds	1,258.7	1,416.5
Spent Nuclear Fuel Obligation (a)	270.8	268.6
Other Long-term Debt	1,134.8	1,127.4
Total Long-term Debt Outstanding	22,032.0	21,173.3
Long-term Debt Due Within One Year	2,281.4	1,753.7
Long-term Debt	$19,750.6	$ 19,419.6

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for spent nuclear fuel disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $314 million and $312 million as of June 30, 2018 and December 31, 2017, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2018 are shown in the tables below:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEP Texas	Senior Unsecured Notes	$ 500.0	3.95	2028
APCo	Pollution Control Bonds	104.4	2.625	2022
I&M	Other Long-term Debt	200.0	Variable	2021
I&M	Notes Payable	55.5	Variable	2022
I&M	Pollution Control Bonds	100.0	3.05	2025
I&M	Senior Unsecured Notes	350.0	3.85	2028
OPCo	Senior Unsecured Notes	400.0	4.15	2048
SWEPCo	Senior Unsecured Notes	450.0	3.85	2048
Non-Registrant:				
Transource Energy	Other Long-term Debt	8.7	Variable	2020
WPCo	Pollution Control Bonds	65.0	3.00	2022
Total Issuances		$ 2,233.6		

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

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		(in millions)	(%)	
AEP Texas	Securitization Bonds	$ 70.0	5.17	2018
AEP Texas	Senior Unsecured Notes	30.0	5.89	2018
AEP Texas	Securitization Bonds	27.6	1.976	2020
AEP Texas	Securitization Bonds	26.5	5.306	2020
APCo	Securitization Bonds	11.7	2.008	2023
I&M	Other Long-term Debt	200.0	Variable	2018
I&M	Pollution Control Bonds	100.0	1.75	2018
I&M	Notes Payable	2.1	Variable	2019
I&M	Notes Payable	8.7	Variable	2019
I&M	Notes Payable	11.8	Variable	2020
I&M	Notes Payable	13.5	Variable	2021
I&M	Notes Payable	14.2	Variable	2022
I&M	Notes Payable	1.3	Variable	2022
I&M	Other Long-term Debt	0.8	6.00	2025
OPCo	Senior Unsecured Notes	350.0	6.05	2018
OPCo	Securitization Bonds	22.9	2.049	2019
PSO	Other Long-term Debt	0.2	3.00	2027
SWEPCo	Pollution Control Bonds	81.7	4.95	2018
SWEPCo	Senior Unsecured Notes	300.0	5.875	2018
SWEPCo	Other Long-term Debt	0.1	3.50	2023
SWEPCo	Other Long-term Debt	0.1	4.28	2023
SWEPCo	Notes Payable	1.6	4.58	2032
Non-Registrant:				
WPCo	Pollution Control Bonds	65.0	Variable	2018
Total Retirements and Principal Payments		$ 1,339.8		

As of June 30, 2018, trustees held, on behalf of AEP, $574 million of their reacquired Pollution Control Bonds. Of this total, $345 million relates to OPCo.

Long-term Debt Subsequent Events

In July 2018, AEP Texas retired $78 million of Securitization Bonds.

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

In July 2018, OPCo retired $24 million of Securitization Bonds.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 2.5% of consolidated tangible net assets as of June 30, 2018. The method for calculating the consolidated tangible net assets is contractually defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

Corporate Borrowing Program - AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of June 30, 2018 and December 31, 2017 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2018 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of June 30, 2018	Authorized Short-term Borrowing Limit	
	(in millions)						
AEP Texas	$ 390.6	$ 106.9	$ 265.6	$ 60.5	$ 19.0	$ 500.0	
AEPTCo	371.3	123.9	235.5	17.6	(142.8)	795.0	(a)
APCo	295.5	23.7	224.3	23.5	(149.3)	600.0	
I&M	322.1	124.2	257.6	34.3	92.3	500.0	
OPCo	234.0	225.0	135.7	189.4	(213.9)	500.0	
PSO	193.7	—	149.4	—	(118.4)	300.0	
SWEPCo	200.1	296.5	164.2	273.2	(119.9)	350.0	

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

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LP are participants in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of June 30, 2018 and December 31, 2017 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity for the six months ended June 30, 2018 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of June 30, 2018
	(in millions)		
AEP Texas	$ 8.4	$ 8.1	$ 8.1
SWEPCo	2.0	2.0	2.0

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to (borrowings from) AEP as of June 30, 2018 and December 31, 2017 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct borrowing and lending activity with AEP for the six months ended June 30, 2018 is described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of June 30, 2018	Loans to AEP as of June 30, 2018	Authorized Short-term Borrowing Limit	
(in millions)							
$1.1	$ 104.7	$ 1.1	$ 48.4	$ 1.1	$30.0	$ 75.0	(a)

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

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The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Six Months Ended June 30,	
	2018	2017
Maximum Interest Rate	2.52 %	1.44 %
Minimum Interest Rate	1.83 %	0.92 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Six Months Ended June 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for the Six Months Ended June 30,	
Company	2018	2017	2018	2017
AEP Texas	2.28 %	1.18 %	2.28 %	— %
AEPTCo	2.30 %	1.25 %	2.06 %	0.99 %
APCo	2.23 %	1.17 %	2.23 %	1.22 %
I&M	2.16 %	1.20 %	2.37 %	1.18 %
OPCo	2.24 %	1.31 %	2.47 %	0.98 %
PSO	2.24 %	1.23 %	— %	— %
SWEPCo	2.34 %	1.20 %	1.88 %	0.98 %

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

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	2.52 %	1.83 %	2.23 %	1.44 %	— %	1.17 %
SWEPCo	2.52 %	1.83 %	2.23 %	1.44 %	— %	1.17 %

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

Six Months Ended June 30,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2018	2.52 %	1.83 %	2.52 %	1.83 %	2.23 %	2.23 %
2017	1.44 %	0.92 %	1.44 %	0.92 %	1.18 %	1.21 %

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Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

Company	Type of Debt	June 30, 2018 Outstanding Amount	June 30, 2018 Interest Rate (a)	December 31, 2017 Outstanding Amount	December 31, 2017 Interest Rate (a)
		(in millions)		(in millions)	
AEP	Securitized Debt for Receivables (b)	$750.0	1.95 %	$718.0	1.22 %
AEP	Commercial Paper	1,814.0	2.41 %	898.6	1.85 %
SWEPCo	Notes Payable	25.2	3.35 %	22.0	2.92 %
	Total Short-term Debt	$2,589.2		$1,638.6	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the “Transfers and Servicing” accounting guidance.

Credit Facilities

For a discussion of credit facilities, see “Letters of Credit” section of Note 5.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies’ receivables and accelerate AEP Credit’s cash collections.

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

Accounts receivable information for AEP Credit is as follows:

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	2.16 %	1.17 %	1.95 %	1.09 %
Net Uncollectible Accounts Receivable Written Off	$5.3	$5.3	$9.4	$11.2

	June 30, 2018	December 31, 2017
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$1,101.4	$ 925.5
Short-term – Securitized Debt of Receivables	750.0	718.0
Delinquent Securitized Accounts Receivable	55.2	41.1
Bad Debt Reserves Related to Securitization	32.0	28.7

Unbilled Receivables Related to Securitization	332.8	303.2

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

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEP Texas and AEPTCo)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiaries' receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreements were:

Company	June 30, 2018	December 31, 2017
	(in millions)	
APCo	$ 138.6	$ 136.2
I&M	166.3	136.5
OPCo	420.4	367.4
PSO	159.1	115.1
SWEPCo	188.9	138.2

The fees paid to AEP Credit for customer accounts receivable sold were:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2018	2017	2018	2017
	(in millions)			
APCo	$ 1.6	$ 1.3	$ 3.3	$ 2.7
I&M	2.2	1.6	4.3	3.1
OPCo	6.0	4.7	11.6	10.4
PSO	1.9	1.7	3.7	3.2
SWEPCo	2.1	1.8	4.0	3.4

The proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2018	2017	2018	2017
	(in millions)			
APCo	$ 344.9	$ 324.2	$ 745.1	$ 693.9
I&M	444.2	390.7	903.3	809.0
OPCo	671.7	493.1	1,351.7	1,125.4
PSO	383.7	328.7	716.4	615.5
SWEPCo	454.5	404.6	852.0	745.8

13. VARIABLE INTEREST ENTITIES

The disclosures in this note apply to AEP only.

The accounting guidance for “Variable Interest Entities” is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity’s equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity’s economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity’s expected losses or the right to receive the legal entity’s expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for “Variable Interest Entities.” In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

Desert Sky Wind Farm LLC (Desert Sky) and Trent Wind Farm LLC (Trent) (collectively “the LLCs”) were established for the purpose of repowering, owning and operating approximately 310.5 MW of wind-powered electric energy generation facilities in Texas. In January 2018, AEP admitted a nonaffiliate as a member of the LLCs to own and repower Desert Sky and Trent. The nonaffiliate contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. The nonaffiliates’ contribution of $84 million was recorded as Net Property, Plant and Equipment on the balance sheets, which was the fair value as of the contribution date determined based on key input assumptions of the original cost of the full turbine sets and the discounted cash flow benefit associated with the production tax credits available from repowering Desert Sky and Trent based on their expected net capacity, capacity factor and the operational availability. AEP owns 79.9% of the LLCs. As a result, management has concluded that Desert Sky and Trent, collectively, are VIE’s and that AEP is the primary beneficiary based on its power to direct the activities that most significantly impact Desert Sky and Trent’s economic performance. Also in January 2018, Desert Sky and Trent entered into a forward PPA for the sale of power to AEPEP related to deliveries of electricity beginning January 1, 2021 for a 12 year period. Prior to the effective date of the PPA, Desert Sky and Trent will sell power at market rates into ERCOT. AEP and the nonaffiliate will share tax attributes including production tax credits and cash distributions from the operation of the LLCs generally consistent with the ownership percentages. See the table below for the classification of Desert Sky and Trent’s assets and liabilities on the balance sheet:

American Electric Power Company, Inc.
Variable Interest Entities
June 30, 2018

	Desert Sky and Trent (in millions)
ASSETS	
Current Assets	$ 46.6
Net Property, Plant and Equipment	313.6
Other Noncurrent Assets	0.7
Total Assets	$ 360.9
LIABILITIES AND EQUITY	

Current Liabilities	$ 101.0
Noncurrent Liabilities	6.0
Equity	253.9
Total Liabilities and Equity	$ 360.9

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AEP has a call right, which if exercised, would require the nonaffiliate to sell its noncontrolling interest in the LLCs to AEP. The call exercise period is for ninety days, beginning two years after the repowering completion. The nonaffiliates' interest in the LLCs is presented as Redeemable Noncontrolling Interest on the balance sheets. The nonaffiliate holds redemption rights, which if exercised, would require AEP to purchase the nonaffiliates' noncontrolling interest in the LLCs. The redemption right exercise period is for ninety days, beginning three years after the repowering completion. The exercise price for both the call and redemption right are determined using a discounted cash flow model with agreed input assumptions as well as potential updates to certain assumptions reasonably expected based on the actual results of the LLCs. As of June 30, 2018, AEP recorded $70 million of Redeemable Noncontrolling Interest in Mezzanine Equity on the balance sheets.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers
The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended June 30, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
Retail Revenues:							
Residential Revenues	$857.0	$ 530.9	$ —	$ —	$ —	$ —	$ 1,387.9
Commercial Revenues	559.6	325.6	—	—	—	—	885.2
Industrial Revenues	563.1	129.7	—	—	—	—	692.8
Other Retail Revenues	46.3	9.9	—	—	—	—	56.2
Total Retail Revenues	2,026.0	996.1	—	—	—	—	3,022.1
Wholesale and Competitive Retail Revenues:							
Generation Revenues	243.7	—	—	101.1	—	—	344.8
Generation Revenues – Affiliated	1.6	—	—	25.0	—	(26.6)	—
Transmission Revenues	48.7	90.5	78.8	—	46.8	—	264.8
Transmission Revenues – Affiliated	11.9	—	134.2	—	(46.8)	(99.3)	—
Marketing, Competitive Retail and Renewable Revenues	—	—	—	331.4	—	—	331.4
Total Wholesale and Competitive Retail Revenues	305.9	90.5	213.0	457.5	—	(125.9)	941.0
Other Revenues from Contracts with Customers	15.5	38.5	6.3	0.6	33.4	—	94.3
Other Revenues from Contracts with Customers – Affiliated	26.1	7.0	2.1	(0.5)	(12.1)	(22.6)	—
Total Revenues from Contracts with Customers	2,373.5	1,132.1	221.4	457.6	21.3	(148.5)	4,057.4
Other Revenues:							
Alternative Revenues	(10.3)	(16.4)	(8.9)	—	—	—	(35.6)
Other Revenues	(14.2)	—	—	3.1	2.5	—	(8.6)
Other Revenues – Affiliated	—	21.3	—	—	—	(21.3)	—
Total Other Revenues	(24.5)	4.9	(8.9)	3.1	2.5	(21.3)	(44.2)
Total Revenues	$2,349.0	$ 1,137.0	$ 212.5	$ 460.7	$ 23.8	$ (169.8)	$ 4,013.2

	Six Months Ended June 30, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 1,858.2	$ 1,098.8	$ —	$ —	$ —	$ —	$ 2,957.0
Commercial Revenues	1,075.4	625.9	—	—	—	—	1,701.3
Industrial Revenues	1,082.0	242.9	—	—	—	—	1,324.9
Other Retail Revenues	90.1	19.4	—	—	—	—	109.5
Total Retail Revenues	4,105.7	1,987.0	—	—	—	—	6,092.7
Wholesale and Competitive Retail Revenues:							
Generation Revenues	457.7	—	—	246.2	—	—	703.9
Generation Revenues – Affiliated	4.6	—	—	52.1	—	(56.7)	—
Transmission Revenues	106.6	184.6	135.6	—	46.8	—	473.6
Transmission Revenues – Affiliated	29.0	—	296.9	—	(46.8)	(279.1)	—
Marketing, Competitive Retail and Renewable Revenues	—	—	—	641.1	—	—	641.1
Total Wholesale and Competitive Retail Revenues	597.9	184.6	432.5	939.4	—	(335.8)	1,818.6
Other Revenues from Contracts with Customers	50.2	87.5	6.6	2.3	38.4	—	185.0
Other Revenues from Contracts with Customers – Affiliated	31.3	7.7	3.8	—	4.9	(47.7)	—
Total Revenues from Contracts with Customers	4,785.1	2,266.8	442.9	941.7	43.3	(383.5)	8,096.3
Other Revenues:							
Alternative Revenues	(19.4)	(10.4)	(24.9)	—	—	—	(54.7)
Other Revenues	(8.7)	—	—	24.1	4.5	—	19.9
Other Revenues – Affiliated	—	43.0	—	—	—	(43.0)	—
Total Other Revenues	(28.1)	32.6	(24.9)	24.1	4.5	(43.0)	(34.8)
Total Revenues	$ 4,757.0	$ 2,299.4	$ 418.0	$ 965.8	$ 47.8	$ (426.5)	$ 8,061.5

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The tables below represent revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Three Months Ended June 30, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCO
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 143.2	$ —	$ 282.3	$ 163.0	$ 388.1	$ 169.5	$ 158.2
Commercial Revenues	109.4	—	141.1	123.4	215.2	107.7	125.9
Industrial Revenues	26.7	—	152.0	144.6	103.8	74.8	85.2
Other Retail Revenues	6.4	—	18.8	1.5	3.3	22.2	2.1
Total Retail Revenues	285.7	—	594.2	432.5	710.4	374.2	371.4
Wholesale Revenues:							
Generation Revenues	—	—	28.1	141.0	—	8.3	55.7
Generation Revenues – Affiliated	—	—	28.7	1.1	—	—	—
Transmission Revenues	78.0	52.6	11.4	3.9	12.0	4.9	16.8
Transmission Revenues – Affiliated	—	130.8	3.1	—	—	0.4	5.0
Total Wholesale Revenues	78.0	183.4	71.3	146.0	12.0	13.6	77.5
Other Revenues from Contracts with Customers	6.8	4.6	0.5	(0.2)	32.3	3.8	4.9
Other Revenues from Contracts with Customers – Affiliated	0.4	1.8	14.6	26.1	6.6	1.1	0.4
Total Revenues from Contracts with Customers	370.9	189.8	680.6	604.4	761.3	392.7	454.2
Other Revenues:							
Alternative Revenues	0.2	(6.0)	(13.6)	(0.5)	(16.6)	5.6	2.9
Other Revenues	—	—	—	(14.2)	(0.8)	—	—
Other Revenues – Affiliated	17.2	—	—	—	4.9	—	—
Total Other Revenues	17.4	(6.0)	(13.6)	(14.7)	(12.5)	5.6	2.9
Total Revenues	$ 388.3	$ 183.8	$ 667.0	$ 589.7	$ 748.8	$ 398.3	$ 457.1

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	Six Months Ended June 30, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCO
	(in millions)						
Retail Revenues:							
Residential Revenues	$274.8	$—	$696.3	$352.0	$824.9	$310.6	$ 298.3
Commercial Revenues	214.8	—	288.2	234.2	409.9	195.7	236.0
Industrial Revenues	52.5	—	298.8	275.4	191.5	140.2	160.6
Other Retail Revenues	12.6	—	38.4	3.7	6.5	40.5	4.2
Total Retail Revenues	554.7	—	1,321.7	865.3	1,432.8	687.0	699.1
Wholesale Revenues:							
Generation Revenues	—	—	50.4	252.1	—	14.2	115.6
Generation Revenues – Affiliated	—	—	69.2	4.0	—	—	—
Transmission Revenues	156.0	100.9	28.3	10.7	28.0	15.5	37.0
Transmission Revenues – Affiliated	—	290.9	11.0	—	—	0.4	10.8
Total Wholesale Revenues	156.0	391.8	158.9	266.8	28.0	30.1	163.4
Other Revenues from Contracts with Customers	13.5	4.7	10.7	7.5	74.6	6.9	10.7
Other Revenues from Contracts with Customers – Affiliated	0.8	3.8	15.6	41.1	6.6	2.2	0.7
Total Revenues from Contracts with Customers	725.0	400.3	1,506.9	1,180.7	1,542.0	726.2	873.9
Other Revenues:							
Alternative Revenues	(0.1)	(23.0)	(19.5)	(5.5)	(10.3)	8.9	2.6
Other Revenues	—	—	—	(8.7)	—	—	—
Other Revenues – Affiliated	35.0	—	—	—	8.0	—	—
Total Other Revenues	34.9	(23.0)	(19.5)	(14.2)	(2.3)	8.9	2.6
Total Revenues	$759.9	$377.3	$1,487.4	$1,166.5	$1,539.7	$735.1	$ 876.5

Performance Obligations

AEP has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for “Revenue from Contracts with Customers” allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity’s measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. AEP subsidiaries elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for AEP’s subsidiaries are summarized as follows:

Retail Revenues

AEP’s subsidiaries within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments have performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer’s usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between AEP's subsidiaries and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice. Payments from Retail Electric Providers are due to AEP Texas within 35 days.

Wholesale Revenues - Generation

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments have performance obligations to sell electricity to wholesale customers from generation assets in PJM, SPP and ERCOT. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments also have performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales within the Vertically Integrated Utilities segment are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenue tables above.

Wholesale Revenues - Generation Affiliated

APCo has a performance obligation to supply wholesale electricity to KGPCo through a purchased power agreement. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the TRA. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues - Affiliated line in the disaggregated revenue tables above.

Wholesale Revenues - Transmission

AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco segments have performance obligations to transmit electricity to wholesale customers through assets owned and operated by AEP subsidiaries. The performance obligation to provide transmission services in PJM, SPP and ERCOT encompass a time frame greater than a year, where the performance obligation within each RTO is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP and ERCOT and weekly for PJM.

AEP subsidiaries within the PJM and SPP regions collect revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenue tables above. AEP subsidiaries within the ERCOT region collect revenues through a combination of base rates and interim Transmission Costs of Services filings that are approved by the PUCT.

Wholesale Revenues - Transmission Affiliated

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the Transmission Agreement (TA), which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. PSO, SWEPCO and AEPSC are parties to the Transmission Coordination Agreement (TCA) by and among PSO, SWEPCO and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. AEPTCo is a load serving entity within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. Affiliate revenues as a result of the respective TA and the TCA are reflected as Transmission Revenues - Affiliated in the disaggregated revenue tables above.

Marketing, Competitive Retail and Renewable Revenues

AEP's subsidiaries within the Generation & Marketing segment have performance obligations to deliver electricity to competitive retail and wholesale customers. Performance obligations for marketing, competitive retail and renewable offtake sales are satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are primarily variable as they are subject to customer's usage requirements; however, certain contracts mandate a delivery of a set quantity of electricity at a predetermined price, resulting in a fixed performance obligation.

Payment terms under marketing arrangements typically follow standard Edison Electric Institute and International Swaps and Derivatives Association terms, which call for payment in 20 days. Payments for competitive retail and offtake arrangements for renewable assets range from 15 to 60 days and are dependent on the product sold, location and the creditworthiness of customer. Invoices for marketing arrangements, competitive retail and offtake arrangements for renewable assets are issued monthly.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of June 30, 2018. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The amounts shown in the table below include affiliated and nonaffiliated revenues except for AEP.

Company	2018	2019-2020	2021-2022	After 2022	Total
	(in millions)				
AEP	$503.6	$ 271.0	$ 166.7	$348.7	$1,290.0
AEP Texas	155.6	—	—	—	155.6
AEPTCo	332.1	—	—	—	332.1
APCo	61.3	32.5	25.0	11.4	130.2
I&M	14.0	8.8	8.7	4.3	35.8
OPCo	43.0	12.4	—	—	55.4
PSO	8.2	—	—	—	8.2
SWEPCo	16.7	—	—	—	16.7

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have any material contract assets as of June 30, 2018.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have any material contract liabilities as of June 30, 2018.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrants' balance sheets within the Accounts Receivable - Customers line item. The Registrants' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of June 30, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 for additional information related to AEP Credit's securitized accounts receivable.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Company	June 30, 2018	January 1, 2018
	(in millions)	
AEPTCo	$ 87.8	$ 47.1
APCo	47.1	35.6
I&M	25.7	15.1
OPCo	42.3	26.1
PSO	12.1	6.1
SWEPCo	16.4	11.0

Contract Costs

Contract costs to obtain or fulfill a contract for AEP subsidiaries within the Generation & Marketing segment are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current and noncurrent assets on the Registrants' balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on the Registrants' income statements. The Registrants did not have material contract costs as of June 30, 2018.

CONTROLS AND PROCEDURES

During the second quarter of 2018, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of June 30, 2018, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2018 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2017 includes a detailed discussion of risk factors. As of June 30, 2018, the risk factor appearing in the 2017 Annual Report on Form 10-K under the heading set forth below is supplemented and updated as follows:

Certain elements of AEP’s transmission formula rates have been challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus have an adverse effect on AEP’s business, financial condition, results of operations and cash flows. (Applies to all Registrants other than AEP Texas)

AEP provides transmission service under rates regulated by the FERC. The FERC has approved the cost-based formula rate templates used by AEP to calculate its respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of AEP’s rates accepted or approved by the FERC, including the formula rate templates, the rates of return on the actual equity portion of its respective capital structures and the approved targeted capital structures, are subject to challenge by interested parties at the FERC, or by the FERC on its own initiative. In addition, interested parties may challenge the annual implementation and calculation by AEP of its projected rates and formula rate true up pursuant to its approved formula rate templates under AEP’s formula rate implementation protocols. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC will make appropriate prospective adjustments to them and/or disallow any of AEP’s inclusion of those aspects in the rate setting formula.

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).

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 approved base ROE. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement. Management believes its financial statements adequately address the impact of the settlement agreement. If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition. A decision from the FERC is pending.

In June 2017, a similar complaint was filed with the FERC claiming that the base ROE used by certain AEP subsidiaries that operate in SPP, including the West Transcos, in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to AEP, particularly if rates for delivered electricity increase substantially.

OVEC may require additional liquidity and other capital support. (Applies to AEP, APCo, I&M and OPCo)

AEP and several nonaffiliated utility companies own OVEC. The Inter-Company Power Agreement (ICPA) defines the rights and obligations and sets the power participation ratio of the parties to it. Under the ICPA, parties are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. If a party fails to make payments owed by it under the ICPA, OVEC may not have sufficient funds to honor its payment obligations, including its ongoing operating expenses as well as its indebtedness. As of June 30, 2018, OVEC has outstanding indebtedness of approximately $1.4 billion, of which APCo, I&M, and OPCo are collectively responsible for $615 million through the ICPA. Although they are not an obligor or guarantor, APCo, I&M, and OPCo are responsible for their respective ratio of OVEC's outstanding debt through the ICPA.

A nonaffiliated party, whose aggregate power participation ratio is 4.85% under the ICPA, has filed a petition seeking protection under bankruptcy law. Bankruptcy filings typically trigger review of the petitioner's contractual obligations, including, in this instance, the ICPA. Because the ICPA is subject to FERC approval and jurisdiction, prior to the bankruptcy petition OVEC made a filing at FERC seeking, among other objectives, to confirm FERC's jurisdiction. Litigation related to these filings continues. In addition, as a result of these and prior related developments, OVEC's credit ratings have been impacted.

If OVEC does not have sufficient funds to honor its payment obligations, there is risk that APCo, I&M and/or OPCo may need to make payments in addition to their power participation ratio payments. Further, if OVEC's indebtedness is accelerated for any reason, there is risk that APCo, I&M and/or OPCo may be required to pay some or all of such accelerated indebtedness in amounts equal to their aggregate power participation ratio of 43.47%. Also, as a result of the credit rating agencies' actions, OVEC's ability to access capital markets on terms as favorable as previously may diminish and its financing costs will increase.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended June 30, 2018.

Item 5. Other Information

None

Item 6. Exhibits

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
12	Computation of Consolidated Ratio of Earnings to Fixed Charges	X	X	X	X	X	X	X	X
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
95	Mine Safety Disclosures								X
101.INS	XBRL Instance Document	X	X	X	X	X	X	X	X
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TEXAS INC.
AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: July 26, 2018