Appendix A to the
Proxy Statement

American Electric Power

2018 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AMERICAN ELECTRIC POWER®

BOUNDLESS ENERGY℠

CONTENTS

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Utilities	AEP Utilities, Inc., a former subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. Effective December 31, 2016, TCC and TNC were merged into AEP Utilities, Inc. Subsequently following this merger, the assets and liabilities of CSW Energy, Inc. were transferred to a competitive affiliate company and AEP Utilities, Inc. was renamed AEP Texas Inc.
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 wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
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.
ARO	Asset Retirement Obligations.
ASC	Accounting Standard Codification.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A generation plant consisting of three coal-fired generating units totaling 1,695 MW located in Conesville, Ohio. The plant is jointly owned by AGR and a nonaffiliate.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.

Term	Meaning
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSAPR	Cross-State Air Pollution Rule.
CWA	Clean Water Act.
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.
DOE	U. S. Department of Energy.
Desert Sky	Desert Sky Wind Farm, a 168 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.
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.
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.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
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 FAC Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
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	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.

Term	Meaning
MATS	Mercury and Air Toxics Standards.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
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.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
Oklaunion Power Station	A single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant is jointly owned by AEP Texas, PSO and certain nonaffiliated entities.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OSS	Off-system Sales.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
Price River	Rights and interests in certain coal reserves located in Carbon County, Utah.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Putnam	Rights and interests in certain coal reserves located in Putnam, Mason and Jackson Counties, West Virginia.
Racine	A generation plant consisting of two hydroelectric generating units totaling 47.5 MWs located in Racine, Ohio and owned by AGR.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
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.

Term	Meaning
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.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	Formerly AEP Texas North Company, now a division of AEP Texas.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Trent	Trent Wind Farm, a 154 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The estimated $4.5 billion project included the acquisition of a wind generation facility, totaling approximately 2,000 MWs of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
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," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and 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:

- Changes in economic conditions, electric 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.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build or acquire 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 and environmental compliance.
- 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.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

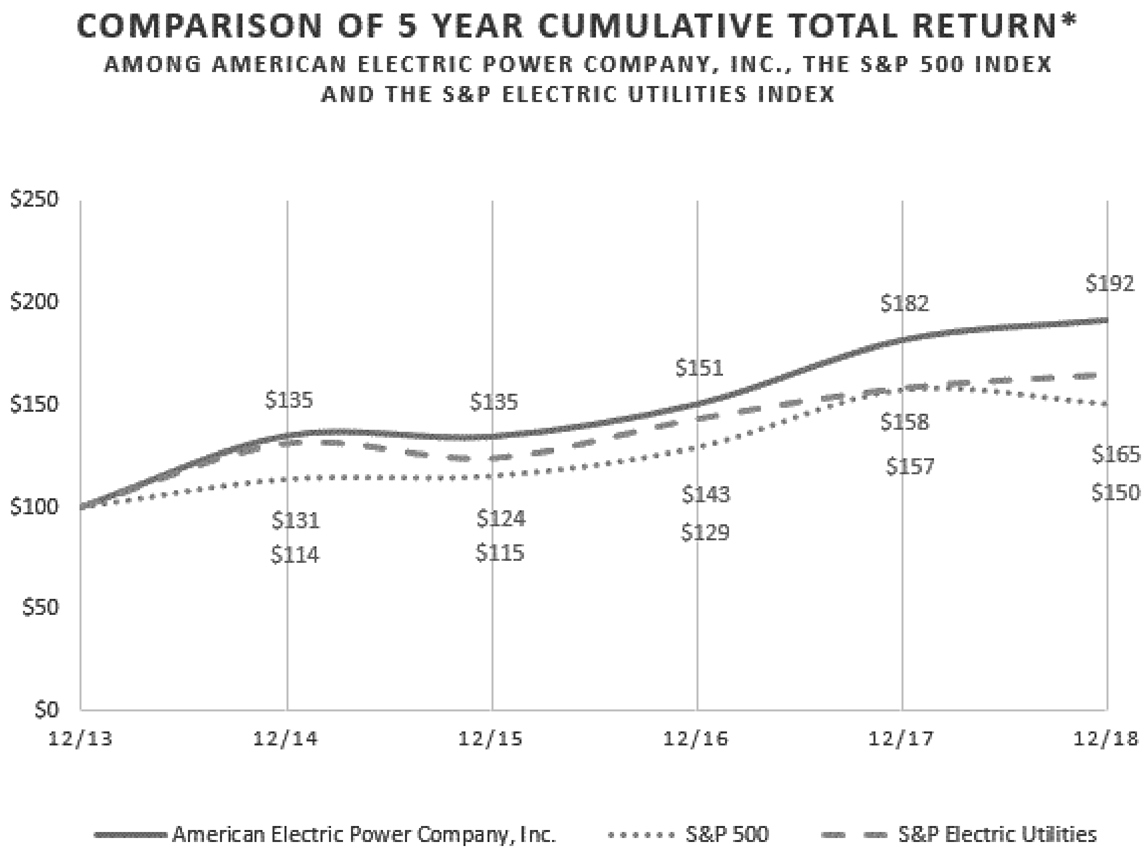
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.

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 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.

AEP COMMON STOCK INFORMATION

AEP common stock is principally traded using the trading symbol "AEP" on the New York Stock Exchange. As of December 31, 2018, AEP had approximately 60,000 registered shareholders.



*$100 invested on 12/31/13 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

Copyright© 2019 Standard & Poor's, a division of S&P Global. All rights reserved.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2018 (a)	2017	2016	2015	2014
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$16,195.7	$15,424.9	$16,380.1	$16,453.2	$16,378.6
Operating Income (c)	$ 2,682.7	$ 3,525.0	$ 1,163.9	$ 3,292.4	$ 3,123.3
Income from Continuing Operations	$ 1,931.3	$ 1,928.9	$ 620.5	$ 1,768.6	$ 1,590.5
Income (Loss) From Discontinued Operations, Net of Tax	—	—	(2.5)	283.7	47.5
Net Income	1,931.3	1,928.9	618.0	2,052.3	1,638.0
Net Income Attributable to Noncontrolling Interests	7.5	16.3	7.1	5.2	4.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,923.8	$ 1,912.6	$ 610.9	$ 2,047.1	$ 1,633.8
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$73,085.2	$67,428.5	$62,036.6	$65,481.4	$63,605.9
Accumulated Depreciation and Amortization	17,986.1	17,167.0	16,397.3	19,348.2	19,970.8
Total Property, Plant and Equipment – Net	$55,099.1	$50,261.5	$45,639.3	$46,133.2	$43,635.1
Total Assets	$68,802.8	$64,729.1	$63,467.7	$61,683.1	$59,544.6
Total AEP Common Shareholders' Equity	$19,028.4	$18,287.0	$17,397.0	$17,891.7	$16,820.2
Noncontrolling Interests	$ 31.0	$ 26.6	$ 23.1	$ 13.2	$ 4.3
Long-term Debt (b)	$23,346.7	$21,173.3	$20,256.4	$19,572.7	$18,512.4
Obligations Under Capital Leases (b)	$ 289.0	$ 297.8	$ 305.5	$ 343.5	$ 362.8
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
From Continuing Operations	$ 3.90	$ 3.89	$ 1.25	$ 3.59	$ 3.24
From Discontinued Operations	—	—	(0.01)	0.58	0.10
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.90	$ 3.89	$ 1.24	$ 4.17	$ 3.34
Weighted Average Number of Basic Shares Outstanding (in millions)	492.8	491.8	491.5	490.3	488.6
Market Price Range:					
High	$ 81.05	$ 78.07	$ 71.32	$ 65.38	$ 63.22
Low	$ 62.71	$ 61.82	$ 56.75	$ 52.29	$ 45.80
Year-end Market Price	$ 74.74	$ 73.57	$ 62.96	$ 58.27	$ 60.72
Cash Dividends Declared per AEP Common Share	$ 2.53	$ 2.39	$ 2.27	$ 2.15	$ 2.03
Dividend Payout Ratio	64.87%	61.44%	183.06%	51.56%	60.78%
Book Value per AEP Common Share	$ 38.58	$ 37.17	$ 35.38	$ 36.44	$ 34.37

(a) The 2018 financial results include pretax asset impairments of $71 million. See Note 7 - Dispositions and Impairments for additional information.
(b) Includes portion due within one year.
(c) Amounts reflect the adoption of ASU 2017-07 "Compensation - Retirement Benefits." See Note 2 - New Accounting Pronouncements for additional information.

EXECUTIVE OVERVIEW

Company Overview

AEP is one of the largest investor-owned electric public utility holding companies in the United States. AEP's electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

AEP's subsidiaries operate an extensive portfolio of assets including:

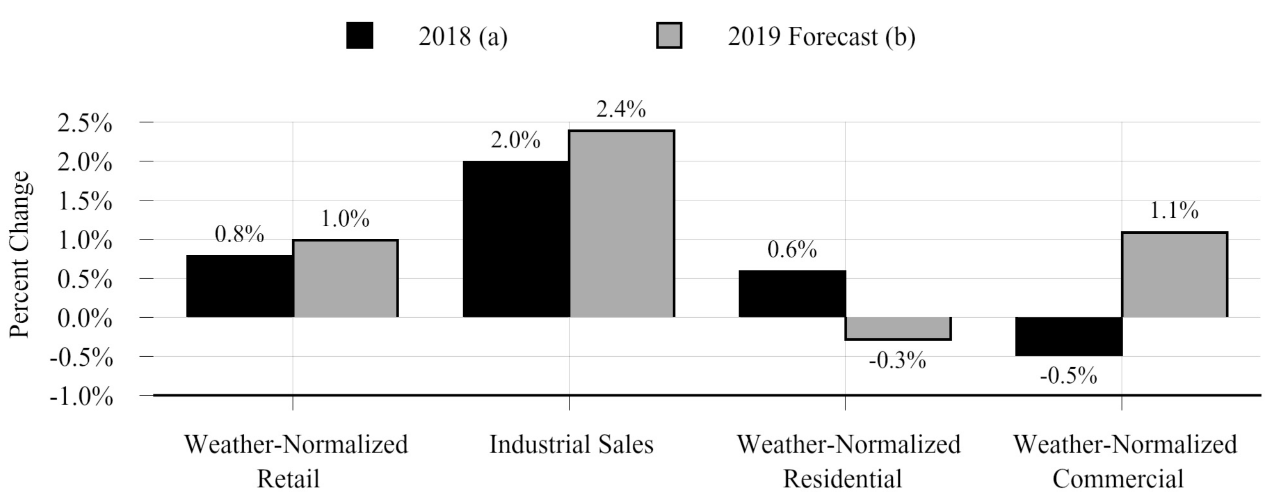
- Approximately 220,000 miles of distribution lines that deliver electricity to 5.4 million customers.
- Approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 23,000 megawatts of regulated owned generating capacity and approximately 4,900 megawatts of regulated PPA capacity in 3 RTOs as of December 31, 2018, one of the largest complements of generation in the United States.

Customer Demand

AEP's weather-normalized retail sales volumes for the year ended December 31, 2018 increased by 0.8% from the year ended December 31, 2017. AEP's 2018 industrial sales volumes increased 2% compared to 2017. The growth in industrial sales was spread across all operating companies and many industries. Weather-normalized residential sales increased 0.6% driven by strong growth in customer counts. Weather-normalized commercial sales decreased by 0.5% in 2018 compared to 2017.

In 2019, AEP anticipates weather-normalized retail sales volumes will increase by 1%. The industrial class is expected to increase by 2.4% in 2019, while weather-normalized residential sales volumes are projected to decrease by 0.3%. Weather-normalized commercial sales volumes are projected to increase by 1.1%.

Percentage Change in Sales Volume



(a) Percentage change for the year ended December 31, 2018 as compared to the year ended December 31, 2017.
(b) Forecasted percentage change for the year ended December 31, 2019 compared to the year ended December 31, 2018.

Regulatory Matters

AEP's public utility subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Depending on the outcomes, these rate and regulatory proceedings can have a material impact on results of operations, cash flows and possibly financial condition. The following are key proceedings that AEP is currently involved in. See Note 4 - Rate Matters for additional information.

- *Hurricane Harvey and Texas Storm Cost Securitization* - In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. In August 2018, AEP Texas filed a Determination of System Restoration Costs with the PUCT for total net storm costs, including storms previous to Hurricane Harvey, in the amount of $370 million. In November 2018, AEP Texas, the PUCT staff and intervenors filed a stipulation and settlement agreement with the PUCT that reduced the $370 million of total net storm costs to $354 million to reflect the impact of settlement agreement adjustments and additional insurance proceeds received. The net storm costs of $354 million are inclusive of a $152 million regulatory asset for deferred storm costs. AEP Texas is planning to make a filing in the first half of 2019 to request securitization of estimated distribution related assets of $247 million. The remaining $107 million of estimated transmission related assets is expected to be recovered through interim transmission filings or an upcoming base rate case.

- *Virginia Legislation Affecting Earnings Reviews* - In March 2018, Virginia enacted legislation requiring APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years ("triennial review"). Triennial reviews are subject to an earnings test which provides that 70% of any earnings exceeding 70 basis points over the Virginia SCC authorized return on common equity would be refunded, or may be offset by capital expenditures in approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. Management has reviewed APCo's actual and forecasted earnings for the triennial period and concluded that it is not probable but is reasonably possible that APCo will over-earn in Virginia during the 2017-2019 triennial period. Due to various uncertainties, including weather, storm restoration, weather-normalized demand and potential customer shopping during 2019, management cannot estimate a range of potential APCo Virginia over-earnings during the 2017-2019 triennial period.

- *Virginia Staff Depreciation Study Request* - In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia Staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of APCo's triennial review, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review.

- *2016 SEET Filing* - Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. In 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 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016. In January 2018, PUCO staff filed testimony that OPCo did not have significantly excessive earnings in 2016. Also in January 2018, an intervenor filed testimony recommending a $53 million refund to customers related to OPCo 2016 SEET earnings. In February 2018, OPCo and PUCO staff filed a stipulation agreement in which both parties agreed that OPCo did not have significantly excessive earnings in 2016. A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the first half of 2019. While management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group or adopt a different 2016 SEET threshold.

- *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. In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals, which was denied. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. As of December 31, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

- *FERC Transmission Complaint - AEP's PJM Participants* - In 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 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 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 and increases the cap on the equity portion of the capital structure to 55% from 50%. In April 2018, an ALJ accepted the interim settlement rates, which were implemented effective January 1, 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. In February 2019, the FERC issued an order that requested additional information in order to evaluate the settlement. That order did not rule on the merits of the settlement.

- *FERC Transmission Complaint - AEP's SPP Participants* - In 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. A hearing at the FERC is scheduled for August 2019.

Utility Rates and Rate Proceedings

The Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric service rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Registrants' current and future results of operations, cash flows and financial position.

The following tables show the Registrants' completed and pending base rate case proceedings in 2018. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (in millions)	Approved ROE	New Rates Effective
I&M	Indiana	$ 96.8	9.95%	July 2018
I&M	Michigan	49.9	9.9%	April 2018

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase (in millions)	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
APCo	West Virginia	May 2018	$ 80.2	10.22%	9.75%
PSO	Oklahoma	October 2018	88.4	10.3%	9% - 9.36%
WPCo	West Virginia	May 2018	15.1	10.22%	9.75%

Dolet Hills Lignite Company Operations

In November 2018, SWEPCo and CLECO announced that the Dolet Hills Power Station will change to a seasonal operational strategy. DHLC's mining operation will continue year-round but will reduce its lignite output. SWEPCo's share of the net investment in the Dolet Hills Power Station is $132 million and the maximum exposure of SWEPCo's total investment in DHLC is $190 million. Management will continue to monitor the economic viability of the Dolet Hills Power Station and DHLC.

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. In July 2018, the PUCT denied SWEPCo's request for a Certificate of Public Convenience and Necessity to proceed with the Wind Catcher Project. PSO and SWEPCo subsequently cancelled the Wind Catcher Project. Total expenses incurred for the years ended December 31, 2018 and 2017 were $41 million and $14 million, respectively.

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. The Generation & Marketing segment also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties. As of December 31, 2018, subsidiaries within AEP's Generation & Marketing segment had approximately 436 MWs of contracted renewable generation projects in-service. In addition, as of December 31, 2018, these subsidiaries had approximately 57 MWs of renewable generation projects under construction with total estimated capital costs of $80 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 has contributed its cash equity capital commitment of $235 million related to its 79.9% share of the LLCs, or 261 MWs. The wind farms were fully repowered and placed in-service in the third quarter of 2018. AEP is subject to a put and has a call option after certain conditions are met, either of which would liquidate the nonaffiliated member's interest. See Note 17 - Variable Interest Entities for additional information.

In December 2018, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% interest in a 302 MW wind generation project located in West Texas upon completion. Management expects the transaction to close and the wind generation facility to be in-service in mid-2019.

In February 2019, AEP signed an agreement to purchase Sempra Renewables LLC and its 724 MWs of wind generation and battery assets for approximately $1.1 billion, subject to closing and working capital adjustments. As part of the purchase price, AEP will pay $551 million in cash and assume $343 million of existing project debt obligations of the non-consolidated joint ventures. Additionally, the acquisition will be accompanied by the recognition of non-controlling tax equity interest of $162 million associated with certain of the acquired wind farms. The wind generation portfolio includes seven wholly or jointly-owned wind farms with long-term PPAs for 100% of their energy production. The transaction is expected to close in mid-2019 and is subject to regulatory approvals from the FERC and federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

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. In the second quarter of 2018, the Virginia SCC and WVPSC denied APCo's applications to acquire the two wind generation facilities.

In September 2018, OPCo, consistent with its commitment in the previously approved PPA application, submitted a filing with the PUCO demonstrating a need for up to 900 MWs of economically beneficial renewable resources in Ohio. This filing was followed by a separate filing for two solar Renewable Energy Purchase Agreements totaling 400 MWs. In January 2019, PUCO staff recommended that the PUCO reject OPCo's request. If approved, the solar generation facilities are expected to be operational by the end of 2021.

In January 2019, PSO and SWEPCo issued requests for proposals to acquire up to 1,000 MWs and 1,200 MWs of wind generation, respectively. The wind generation projects would be subject to regulatory approval and placed in-service by the end of 2021.

Federal Tax Reform

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, AEP recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, AEP continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and AEP will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

Status of Tax Reform Regulatory Proceedings

During 2018, state utility commissions issued orders and instructions requiring public utilities, including the Registrants, to provide the benefits of Tax Reform to customers. As of December 31, 2018, the Registrants have received orders and instructions from a majority of the jurisdictions in which they operate. The table below summarizes the various regulatory jurisdictions where the regulatory effects of Tax Reform proceedings have not been fully resolved. See Note 4 - Rate Matters for additional information.

Registrant (Jurisdiction)	Change in Tax Rate	Excess ADIT Subject to Normalization Requirements	Excess ADIT Not Subject to Normalization Requirements
AEP Texas (Texas-Distribution)	Order Issued	Order Issued	Order Issued – Partial (a)
AEP Texas (Texas-Transmission)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
APCo (Virginia)	Legislation Enacted – Case Pending (b)	Legislation Enacted – Case Pending (b)	Order Issued – Partial; Separate Case Pending (c)
I&M (Michigan)	Order Issued	Case Pending	Case Pending
SWEPCo (Louisiana)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)
SWEPCo (Texas)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
PJM FERC Transmission	Settlement Approved (e)	Settlement Approved (e)	Settlement Approved (e)
SPP FERC Transmission	To be addressed in a later filing	To be addressed in a later filing	To be addressed in a later filing

(a) A portion of the Excess ADIT that is not subject to rate normalization requirements is to be addressed in a later filing.
(b) Legislation has been issued for a blanket amount that is subject to true-up and final commission approval.
(c) In October 2018, the Virginia SCC issued an order approving APCo's request to refund a portion of the Excess ADIT that is not subject to rate normalization requirements to customers. The remainder is to be addressed in a separate pending case.
(d) Rates have been implemented through a filed formula rate plan that is subject to true-up and final commission approval.
(e) An ALJ has approved a settlement. The settlement is subject to final FERC ruling.

Merchant Coal Generation Assets

In September 2018, management announced plans to close the Oklaunion Power Station by October 2020. In the fourth quarter of 2018, management announced plans to close Conesville Plant Units 5 and 6 in May 2019 and Unit 4 in May 2020. The closures are not expected to have a material impact on net income, cash flows or financial condition.

Racine

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

Reconstruction activities at Racine continued through 2018. Due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed resulting in an additional impairment of $35 million, representing the total costs previously capitalized during 2018. During the fourth quarter of 2018, there were no significant increases in estimated costs to complete the reconstruction project and no other events were identified that would have triggered the need for an additional impairment analysis at Racine.

Reconstruction activities at Racine are estimated to be completed in the fourth quarter of 2019. AEP expects to incur additional capital expenditures to complete the reconstruction project, at which point the fair value of Racine, as fully operational, is expected to approximate the amount of those remaining estimated capital expenditures. Future revisions in cost estimates could result in additional losses which could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

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

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). 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 December 31, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

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. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies for additional information.

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, refueling 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. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices 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.

The U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims and remanding the case for further proceedings.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. Responsive and supplemental filings have been made by all parties. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to the consent decree. See "Proposed Modification of the NSR Litigation Consent Decree" section below for additional information.

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

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and incurs 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 December 31, 2018, the AEP System had a total generating capacity of approximately 25,400 MWs, of which approximately 13,200 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 SIPs or 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 net book value before cost of removal, including related materials and supplies inventory, of plants or units of plants previously retired that have a remaining net book value as of December 31, 2018.

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	32.5
APCo (a)	Clinch River Plant, Units 1 and 2	470	26.7
APCo	Sporn Plant, Units 1 and 3	300	17.2
APCo	Glen Lyn Plant	335	14.2
SWEPCo	Welsh Plant, Unit 2	528	50.6
Total		2,268	$ 186.0

(a) APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert 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 2016.

Management is seeking or will seek recovery of the remaining net book value in future rate proceedings. To the extent the net book value of these generation assets is not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Proposed Modification of the New Source Review 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 and later filed a detailed statement of the specific relief requested to address the changed circumstances at Rockport Plant, Unit 2. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings on the pending motion to modify the consent decree to facilitate settlement discussions among the parties.

AEP is seeking to modify the consent decree as a means to resolve or substantially narrow the issues in pending litigation with the owners of Rockport Plant, Unit 2. See "Rockport Plant Litigation" section above and Note 6 - 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 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 MATS, (d) implementation and review of CSAPR, a FIP designed to eliminate significant contributions from sources in upwind states to non-attainment 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. Future changes that result from this effort may affect AEP's compliance plans.

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

National Ambient Air Quality Standards

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 non-attainment designations for the remaining areas in 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 were submitted in October 2018. Challenges to the 2015 ozone standard are pending in the U.S. Court of Appeals for the District of Columbia Circuit. In November 2018, the Federal EPA proposed final requirements for implementing the 2015 ozone standard. 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 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 and finalized a FIP in September of 2016. The FIP includes revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls installed to address other CAA requirements. 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 finalized a separate action to revise the SO_2 BART determinations which was challenged before the Arkansas

Pollution Control and Ecology Commission. The ALJ has recommended that the challenge be dismissed. The Federal EPA proposed to approve the Arkansas SO_2 BART determinations, which if the Federal EPA issues final approval, no further emission reductions will be required at the Flint Creek Plant.

The Federal EPA also disapproved portions of the Texas regional haze SIP. In January 2017, the Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including Welsh Plant, Unit 1. The proposed source-specific approach for Welsh Plant, Unit 1 called for installation of a wet FGD system. In October 2017, the Federal EPA finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations as an alternative to source-specific SO_2 requirements. The opportunity to use emissions trading to satisfy the regional haze requirements for NO_x and SO_2 at AEP's affected generating units provides greater flexibility and lower cost compliance options than the original proposal. A challenge to the FIP has been filed in the U.S. Court of Appeals for the Fifth Circuit by various intervenors and the case has been held in abeyance pending the Federal EPA's reconsideration of the final rule. In August 2018, the Federal EPA proposed to affirm its October 2017 FIP approval and requested comment on certain aspects of the FIP promulgation and specifically on the intrastate SO_2 trading program. Management supports the intrastate trading program contained in the FIP as a compliance alternative to source-specific controls.

In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. The rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. 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.

Cross-State Air Pollution Rule

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. 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. 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 non-mercury 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 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 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 and oil-fired units. Petitions for review of the Federal EPA's determination were 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. In December 2018, the Federal EPA released a proposed finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. However, the Federal EPA also proposed that it would not remove the source category or alter MATS and no further reductions are necessary. The comment period on this proposed finding has not yet commenced.

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 President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and the cases are still pending.

In October 2017, the Federal EPA issued a proposed rule repealing the CPP. In December 2017, the Federal EPA issued an advanced notice of proposed rulemaking seeking information that should be considered by the Federal EPA in developing revised guidelines for state programs. In August 2018, the Federal EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE would establish a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. Comments were accepted until the end of October 2018. In December 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. Management is actively monitoring rulemaking activities.

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 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 estimated CO_2 emissions in 2018 were approximately 69 million metric tons, a 59% 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 facilities were required to begin assessment monitoring programs to determine if unacceptable groundwater impacts will trigger future remedial actions. Additional groundwater data has been collected and further studies to design and assess appropriate remedial measures will be undertaken at four facilities in accordance with the rule.

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

In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule. In March 2018, the Federal EPA issued a proposed rule to modify certain provisions of the solid waste management standards and provide additional flexibility to facilities regulated under approved state programs. A final rule was signed in July 2018 that modifies certain compliance deadlines and other requirements in the rule. Additional changes to the minimum performance standards that were contained in the March proposed rule, and changes to respond to the decision of the U.S. Court of Appeals for the District of Columbia Circuit will be addressed in future rulemakings. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for remand of the July 2018 rule. Vacatur of the July 2018 rule could result in significant increases in capital expenditures and operating costs. Management is monitoring these developments and 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 represent an "unpermitted discharge" under the CWA. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA 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. Closure and post-closure costs have been included in ARO in accordance with the 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 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 would be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations filed a petition for reconsideration of the rule with the Federal EPA. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017, but has been challenged in the courts. Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting. Management is actively participating in the reconsideration proceedings.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The final rule was challenged in both courts of appeal and district courts. In January 2018, the U.S. Supreme Court ruled that challenges to the definition of "waters of the United States" must be filed in federal district courts. Challenges to the rule are proceeding, and courts have reached different conclusions about whether the 2015 rule should be implemented, or whether action to delay the implementation date to 2020 was valid. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers released a proposed rule revising the definition, which would replace the definition in the 2015 rule and could significantly alter the scope of certain CWA programs. The comment period for this proposal has not yet commenced.

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

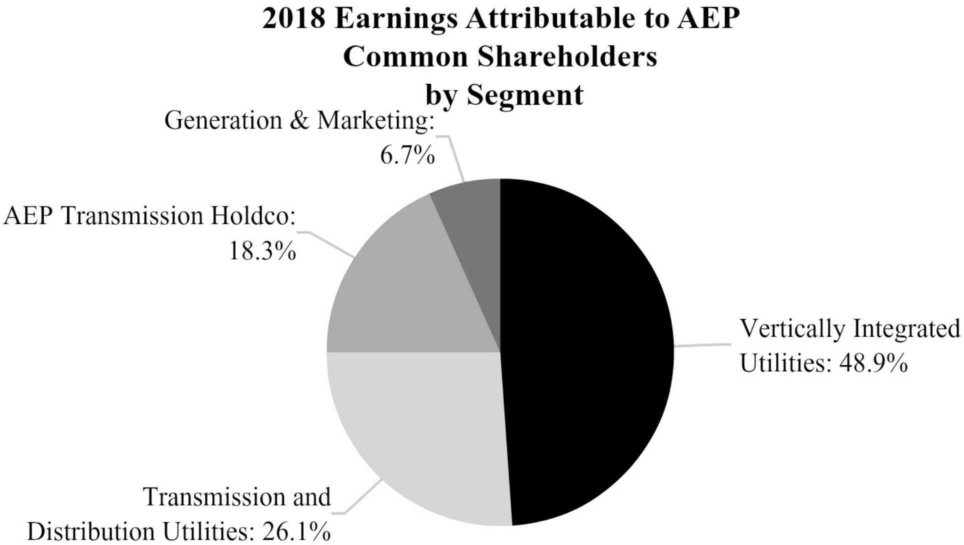
- Competitive generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.
- Contracted renewable energy investments and management services.

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, interest expense, income tax expense and other nonallocated costs.

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

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

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Vertically Integrated Utilities	$ 990.5	$ 790.5	$ 979.9
Transmission and Distribution Utilities	527.4	636.4	482.1
AEP Transmission Holdco	369.9	352.1	266.3
Generation & Marketing	135.3	166.0	(1,198.0)
Corporate and Other	(99.3)	(32.4)	80.6
Earnings Attributable to AEP Common Shareholders	$ 1,923.8	$ 1,912.6	$ 610.9



Note: 2018 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment.

AEP CONSOLIDATED

2018 Compared to 2017

Earnings Attributable to AEP Common Shareholders increased $11 million from $1.91 billion in 2017 to $1.92 billion in 2018 primarily due to:

- An increase in weather-related usage.
- Recovery of incremental utility plant investment through favorable rate proceedings in AEP's various jurisdictions.

These increases were partially offset by:

- An increase in other operation and maintenance expenses primarily within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments.
- An increase in depreciation and amortization expenses primarily due to a higher depreciable base and approved increased depreciation rates in AEP's various jurisdictions.
- A decrease in earnings in the Generation & Marketing segment primarily due to the 2017 gain resulting from the sale of certain merchant generation assets.

2017 Compared to 2016

Earnings Attributable to AEP Common Shareholders increased from $611 million in 2016 to $1.91 billion in 2017 primarily due to:

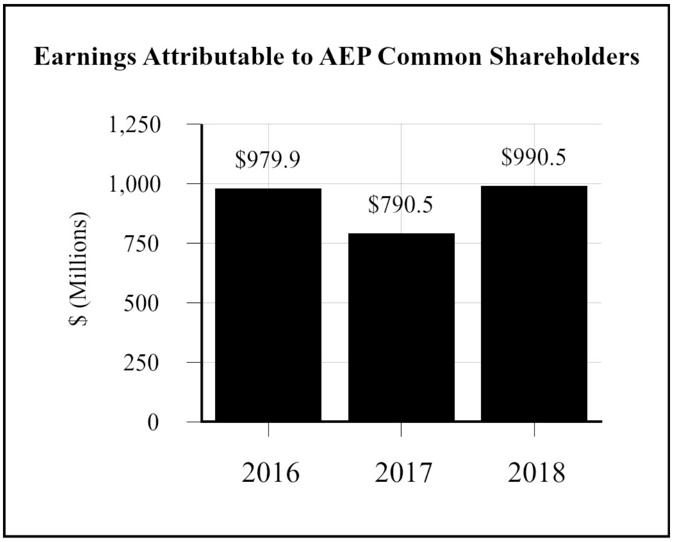
- An increase due to the impairment of certain merchant generation assets in 2016.
- An increase due to the gain on the sale of certain merchant generation assets in 2017.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.
- Favorable rate proceedings in AEP's various jurisdictions.

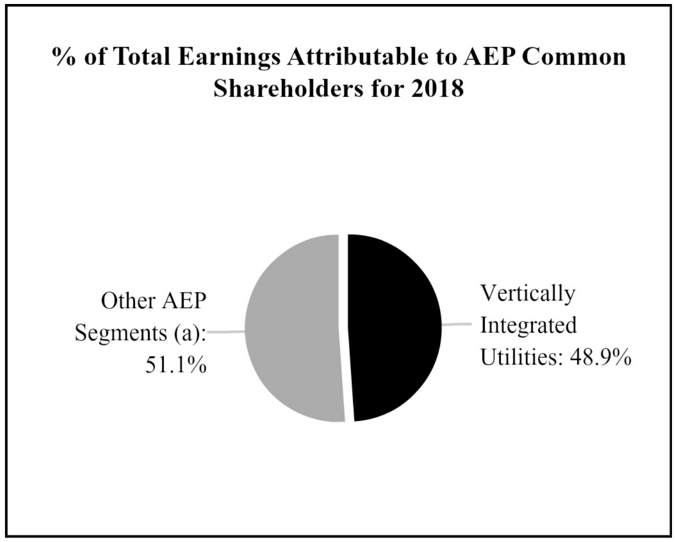
These increases were partially offset by:

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

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

VERTICALLY INTEGRATED UTILITIES





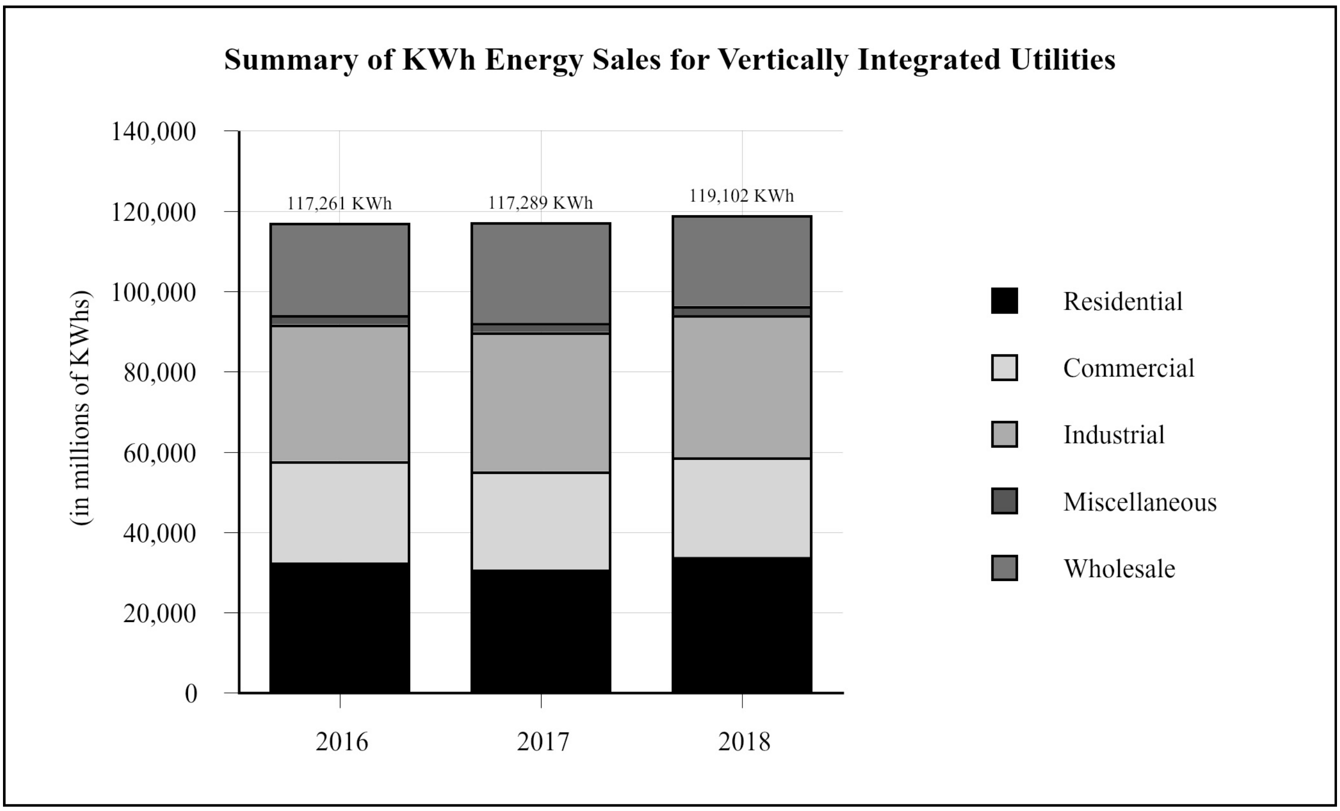
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Vertically Integrated Utilities	Years Ended December 31, 2018	2017	2016
		(in millions)	
Revenues	$ 9,645.5	$ 9,192.0	$ 9,091.9
Fuel and Purchased Electricity	3,488.9	3,142.7	3,079.3
Gross Margin	6,156.6	6,049.3	6,012.6
Other Operation and Maintenance	2,959.8	2,760.7	2,726.6
Asset Impairments and Other Related Charges	3.4	33.6	10.5
Depreciation and Amortization	1,316.2	1,142.5	1,073.8
Taxes Other Than Income Taxes	433.2	413.3	390.8
Operating Income	1,444.0	1,699.2	1,810.9
Interest and Investment Income	11.7	6.8	4.8
Carrying Costs Income	5.3	15.2	10.5
Allowance for Equity Funds Used During Construction	35.4	28.0	45.5
Non-Service Cost Components of Net Periodic Benefit Cost	69.9	23.5	23.7
Interest Expense	(567.8)	(540.0)	(522.1)
Income Before Income Tax Expense and Equity Earnings (Loss)	998.5	1,232.7	1,373.3
Income Tax Expense	5.7	425.6	397.3
Equity Earnings (Loss) of Unconsolidated Subsidiaries	2.7	(3.8)	8.0
Net Income	995.5	803.3	984.0
Net Income Attributable to Noncontrolling Interests	5.0	12.8	4.1
Earnings Attributable to AEP Common Shareholders	$ 990.5	$ 790.5	$ 979.9

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31, 2018	2017	2016
	(in millions of KWhs)		
Retail:			
Residential	33,903	30,817	32,606
Commercial	24,813	24,423	25,229
Industrial	35,378	34,676	34,029
Miscellaneous	2,326	2,275	2,316
Total Retail	96,420	92,191	94,180
Wholesale (a)	22,682	25,098	23,081
Total KWhs	119,102	117,289	117,261

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.

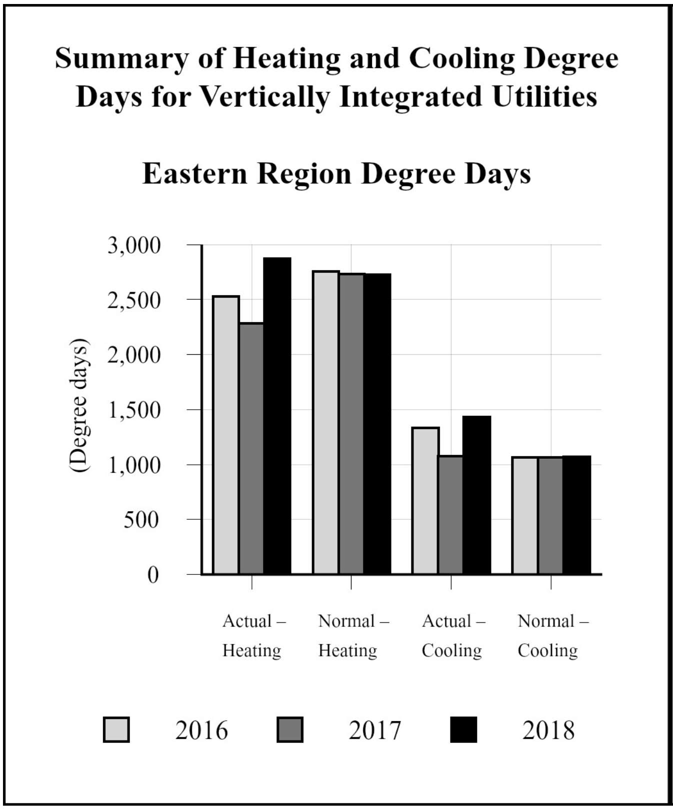


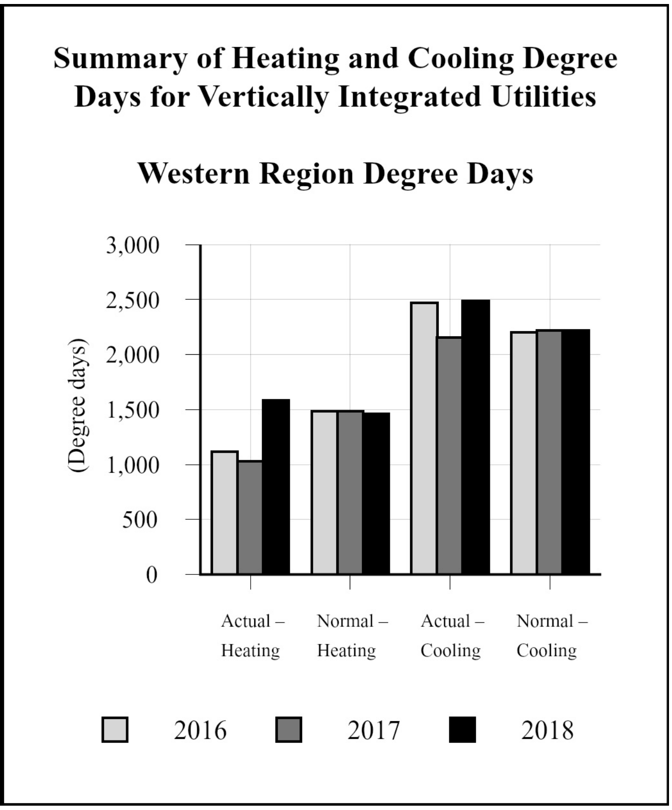
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2018	**2017**	**2016**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,886	2,298	2,541
Normal – Heating (b)	2,738	2,746	2,767
Actual – Cooling (c)	1,443	1,088	1,345
Normal – Cooling (b)	1,083	1,078	1,075
Western Region			
Actual – Heating (a)	1,599	1,040	1,130
Normal – Heating (b)	1,475	1,494	1,495
Actual – Cooling (c)	2,502	2,164	2,480
Normal – Cooling (b)	2,230	2,229	2,215

(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.





2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2017	$	790.5
Changes in Gross Margin:		
Retail Margins		104.7
Off-system Sales		(12.9)
Transmission Revenues		32.9
Other Revenues		(17.4)
Total Change in Gross Margin		107.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(199.1)
Asset Impairments and Other Related Charges		30.2
Depreciation and Amortization		(173.7)
Taxes Other Than Income Taxes		(19.9)
Interest and Investment Income		4.9
Carrying Costs Income		(9.9)
Allowance for Equity Funds Used During Construction		7.4
Non-Service Cost Components of Net Periodic Pension Cost		46.4
Interest Expense		(27.8)
Total Change in Expenses and Other		(341.5)
Income Tax Expense		419.9
Equity Earnings (Loss) of Unconsolidated Subsidiaries		6.5
Net Income Attributable to Noncontrolling Interests		7.8
Year Ended December 31, 2018	$	990.5

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

- **Retail Margins** increased $105 million primarily due to the following:
  - A $251 million increase in weather-related usage across all regions primarily in the residential and commercial classes.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $71 million increase from base rate proceedings for I&M, inclusive of a $47 million decrease due to the impact of Tax Reform in the Indiana jurisdiction.
    - A $52 million increase for PSO due to new base rates implemented in March 2018, inclusive of a $27 million decrease due to the change in the corporate federal tax rate.
    - A $44 million increase for SWEPCo due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
  - A $33 million increase for I&M in FERC generation wholesale municipal and cooperative revenues primarily due to the annual formula rate true-up and changes to the formula rate.
  - A $22 million increase in revenue from rate riders at PSO. This increase was partially offset by corresponding increases to riders/trackers recognized in other expense items below.

  These increases were partially offset by:
  - A $168 million decrease due to riders and customer provisions for refund related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $91 million reduction at APCo and WPCo in deferred fuel under-recovery related to the West Virginia Tax Reform settlements. This decrease was offset in Income Tax Expense below.

    - A $50 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 $29 million decrease in weather-normalized retail margins primarily in the commercial class.
    - A $25 million increase at APCo in net ENEC recoverable PJM expenses that were offset below.
    - A $16 million decrease at PSO related to the System Reliability Rider that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
    - A $10 million increase at APCo in non-recoverable fuel expense related to Virginia legislation.
- **Margins from Off-system Sales** decreased $13 million primarily due to mid-year changes in the OSS sharing mechanism at I&M.
- **Transmission Revenues** increased $33 million primarily due to the following:
    - A $25 million increase at SWEPCo from continued SPP transmission investments.
    - A $22 million increase due to the annual formula rate true-up and decreased PJM provisions.

  These increases were partially offset by:
    - A $16 million decrease at SWEPCo from a 2018 provision for refund related to revenues recorded in prior periods on certain transmission assets that management believes should not have been included in the SPP formula rate.
- **Other Revenues** decreased $17 million primarily due to reduced rates for KPCo Demand Side Management programs beginning in 2018. This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $199 million primarily due to the following:
    - A $46 million increase in plant outage and maintenance expenses primarily for I&M and KPCo.
    - A $42 million increase in SPP transmission services.
    - A $40 million increase in expenses at APCo and WPCo due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense below.
    - A $28 million increase in vegetation management primarily for I&M and APCo.
    - A $27 million increase due to the Wind Catcher Project for SWEPCo and PSO.
    - A $27 million increase in storm-related expenses primarily for APCo.
    - A $26 million increase in employee-related expenses.
    - A $9 million increase due to an increase in estimated expense for claims related to asbestos exposure.
    - A $7 million increase in factoring expense.

  These increases were partially offset by:
    - A $70 million decrease in PJM transmission expenses primarily due to the annual formula rate true-up.
- **Asset Impairments and Other Related Charges** decreased $30 million primarily due to the following:
    - A $34 million decrease at SWEPCo due to Welsh Plant, Unit 2 and Turk Plant asset impairments and other charges related to the 2016 Texas Base Rate Case and the 2017 Louisiana Turk Plant Prudence Review.

  This decrease was partially offset by:
    - A $4 million increase at APCo due to the impairment of assets related to capacity management projects and other investments.
- **Depreciation and Amortization** expenses increased $174 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, PSO and SWEPCo.
- **Taxes Other Than Income Taxes** increased $20 million primarily due to:
    - A $10 million increase in state and local taxes due to higher reported taxable KWh and taxable revenues and a prior period refund.
    - A $9 million increase in property taxes driven by an increase in utility plant.
- **Interest and Investment Income** increased $5 million primarily due to an increase in interest received from the Utility Money Pool as a result of increased investment in 2018 by SWEPCo and I&M.
- **Carrying Costs Income** decreased $10 million primarily due to a decrease in carrying charges for certain riders at I&M.

- **Allowance for Equity Funds Used During Construction** increased $7 million primarily due to an increase in construction activity at APCo and SWEPCo.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $46 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $28 million primarily due to the following:
  - A $13 million increase primarily due to higher long-term debt balances at I&M.
  - A $10 million increase at PSO primarily due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
  - A $5 million increase at SWEPCo primarily due to interest expense credits in 2017 on Welsh Plant and Flint Creek Plant environmental project deferrals and other interest expense accruals for refunds and true-ups in 2018.
- **Income Tax Expense** decreased $420 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT, other book/tax differences which are accounted for on a flow-through basis and a decrease in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** increased $7 million primarily due to a prior period income tax adjustment recognized in 2017.
- **Net Income Attributable to Noncontrolling Interests** decreased $8 million primarily due to 2017 income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense above.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2016	$	979.9
Changes in Gross Margin:		
Retail Margins		6.6
Off-system Sales		12.0
Transmission Revenues		17.3
Other Revenues		0.8
Total Change in Gross Margin		36.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(34.1)
Asset Impairments and Other Related Charges		(23.1)
Depreciation and Amortization		(68.7)
Taxes Other Than Income Taxes		(22.5)
Interest and Investment Income		2.0
Carrying Costs Income		4.7
Allowance for Equity Funds Used During Construction		(17.5)
Non-Service Cost Components of Net Periodic Pension Cost		(0.2)
Interest Expense		(17.9)
Total Change in Expenses and Other		(177.3)
Income Tax Expense		(28.3)
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(11.8)
Net Income Attributable to Noncontrolling Interests		(8.7)
Year Ended December 31, 2017	$	790.5

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

- **Retail Margins** increased $7 million primarily due to the following:
  - The effect of rate proceedings in AEP's service territories which include:
    - A $74 million increase for SWEPCo primarily due to rider and base rate revenue increases in Texas and Louisiana.
    - A $63 million increase for I&M from rate proceedings primarily in Indiana.
    - A $22 million increase for PSO from base rate increases implemented in 2017 and revenue increases from rate riders.
    - A $6 million increase for KGPCo due to revenue increases from rate riders/trackers.

    For the rate increases described above, $87 million relate to riders/trackers which have corresponding increases in expense items below.
  - A $24 million increase primarily due to reduced fuel and other variable production costs not recovered through fuel clauses or other trackers.
  - A $9 million increase in weather-normalized margins due to higher residential and industrial sales partially offset by lower commercial sales.

  These increases were partially offset by:
  - A $133 million decrease in weather-related usage in the eastern and western regions.
  - A $50 million decrease for I&M and SWEPCo in FERC generation wholesale municipal and cooperative revenues primarily due to an annual formula rate true-up and changes to the annual formula rate.
  - A $9 million decrease for APCo primarily due to prior year recognition of deferred billing in West Virginia as approved by the WVPSC.

- **Margins from Off-system Sales** increased $12 million primarily due to higher market prices and increased sales volume.
- **Transmission Revenues** increased $17 million primarily due the following:
  - A $43 million increase primarily due to increases in formula rates driven by continued investment in transmission assets. This increase was partially offset in Expenses and Other items below.

  This increase was partially offset by:
  - A $26 million decrease primarily due to I&M's annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.

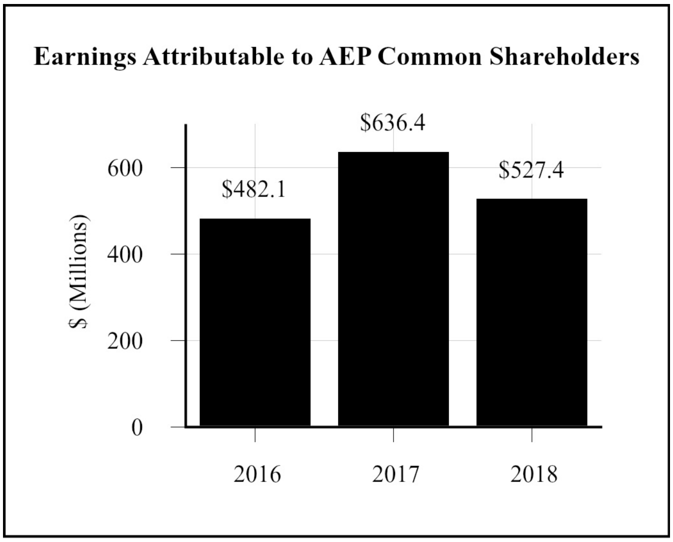
Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiaries and Net Income Attributable to Noncontrolling Interests changed between years as follows:

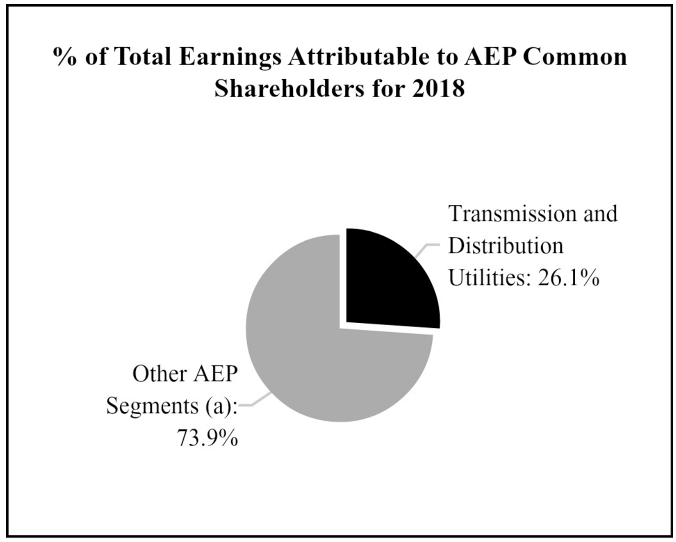
- **Other Operation and Maintenance** expenses increased $34 million primarily due to the following:
  - A $134 million increase in recoverable expenses, primarily PJM expenses, fuel support and energy efficiency expenses fully recovered in rate recovery riders/trackers within Gross Margin above.
  - A $14 million increase due to the Wind Catcher Project for PSO and SWEPCo.

  These increases were partially offset by:
  - A $49 million decrease in employee-related expenses.
  - A $36 million decrease in charitable contributions, primarily to the AEP Foundation.
  - A $17 million decrease in planned plant outages and maintenance primarily in the western region.
  - A $5 million decrease due to an increase in gain on sales of property in 2017.
  - A $4 million decrease due to the reduction of an environmental liability at I&M.
- **Asset Impairments and Other Related Charges** increased $23 million primarily due to the following:
  - A $34 million increase at SWEPCo due to asset impairments of Turk Plant and Welsh Plant, Unit 2 and other charges related to the Texas base rate case.

  This increase was partially offset by:
  - An $11 million decrease due to the impairment of I&M's Price River Coal reserves in 2016.
- **Depreciation and Amortization** expenses increased $69 million primarily due to the following:
  - A $61 million increase primarily due to higher depreciable base.
  - A $22 million increase due to amortization of capitalized software costs.
- **Taxes Other Than Income Taxes** increased $23 million primarily due to higher property taxes.
- **Carrying Costs Income** increased $5 million primarily due to increased deferred carrying charges at I&M for a Cook Life Cycle Management project.
- **Allowance for Equity Funds Used During Construction** decreased $18 million primarily due to completed environmental projects for I&M, PSO and SWEPCo.
- **Interest Expense** increased $18 million primarily due to the following:
  - A $10 million increase primarily due to higher long-term debt balances at I&M.
  - An $8 million increase due to lower AFUDC borrowed funds resulting from reduced CWIP balances.
- **Income Tax Expense** increased $28 million primarily due to the recording of favorable state and federal income tax adjustments in 2016, the recording of federal income tax adjustments related to Tax Reform and other book/tax differences which are accounted for on a flow-through basis, partially offset by a decrease in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $12 million primarily due to a prior period income tax adjustment for DHLC, a SWEPCo unconsolidated subsidiary.
- **Net Income Attributable to Noncontrolling Interests** increased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This increase was offset by a decrease in Income Tax Expense.

TRANSMISSION AND DISTRIBUTION UTILITIES





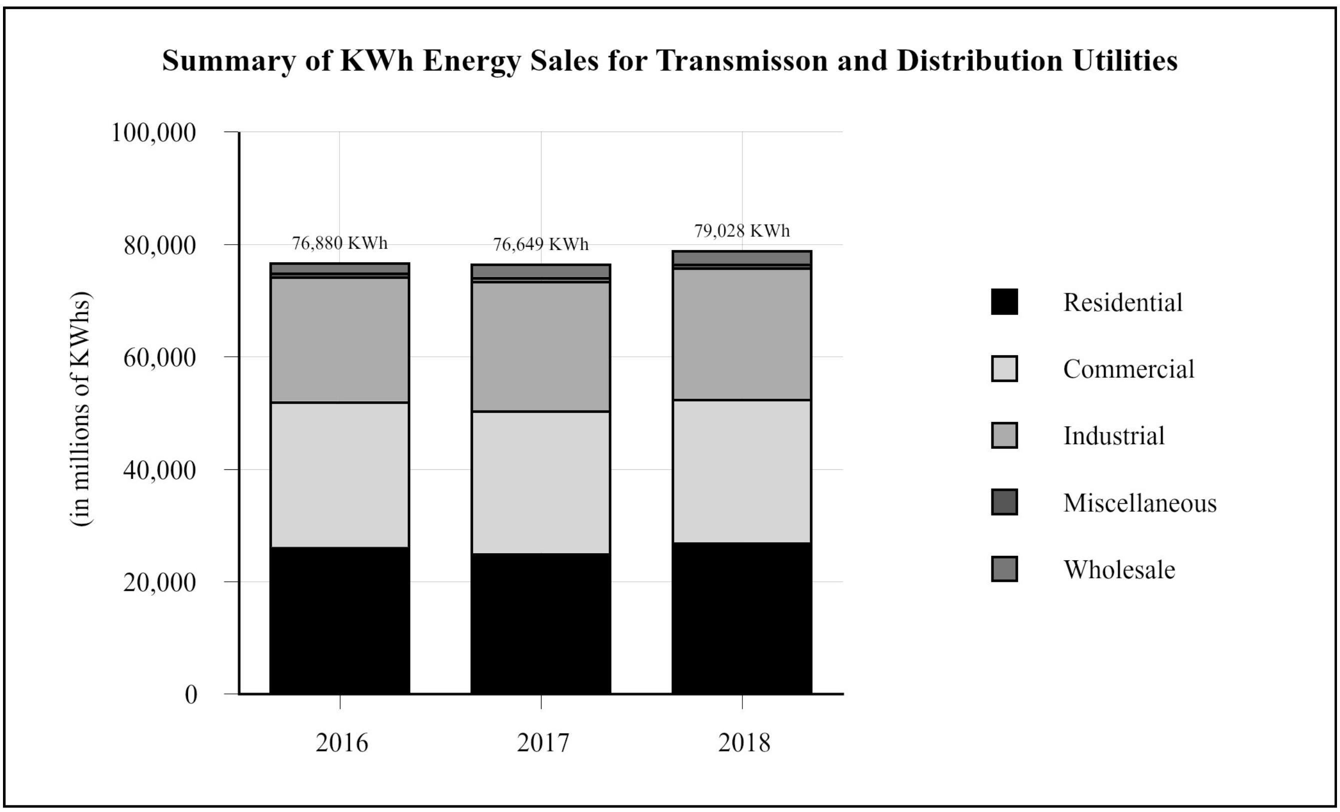
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Transmission and Distribution Utilities	Years Ended December 31, 2018	2017	2016
		(in millions)	
Revenues	$ 4,653.1	$ 4,419.3	$ 4,422.4
Purchased Electricity	858.3	835.3	837.1
Generation Deferrals	—	—	(82.7)
Amortization of Generation Deferrals	223.9	229.2	242.9
Gross Margin	3,570.9	3,354.8	3,425.1
Other Operation and Maintenance	1,541.7	1,199.3	1,395.4
Depreciation and Amortization	734.1	667.5	649.9
Taxes Other Than Income Taxes	545.3	513.7	494.3
Operating Income	749.8	974.3	885.5
Interest and Investment Income	4.2	7.7	14.8
Carrying Costs Income	1.7	3.6	20.0
Allowance for Equity Funds Used During Construction	29.9	13.2	15.1
Non-Service Cost Components of Net Periodic Benefit Cost	32.3	8.9	8.7
Interest Expense	(248.1)	(244.1)	(256.9)
Income Before Income Tax Expense	569.8	763.6	687.2
Income Tax Expense	42.4	127.2	205.1
Net Income	527.4	636.4	482.1
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 527.4	$ 636.4	$ 482.1

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2018	2017	2016
	(in millions of KWhs)		
Retail:			
Residential	27,041	25,108	26,191
Commercial	25,555	25,390	25,922
Industrial	23,310	23,082	22,179
Miscellaneous	681	682	700
Total Retail (a)	76,587	74,262	74,992
Wholesale (b)	2,441	2,387	1,888
Total KWhs	79,028	76,649	76,880

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

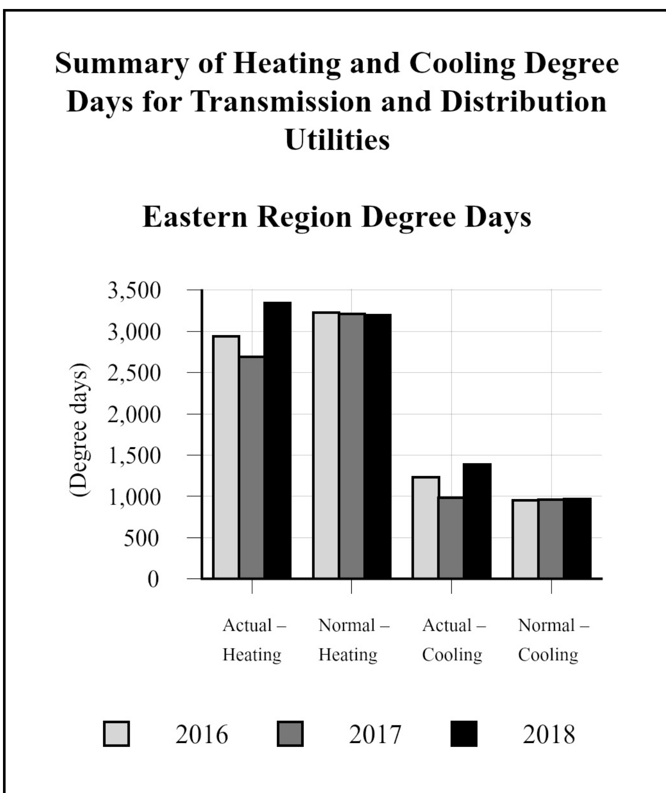


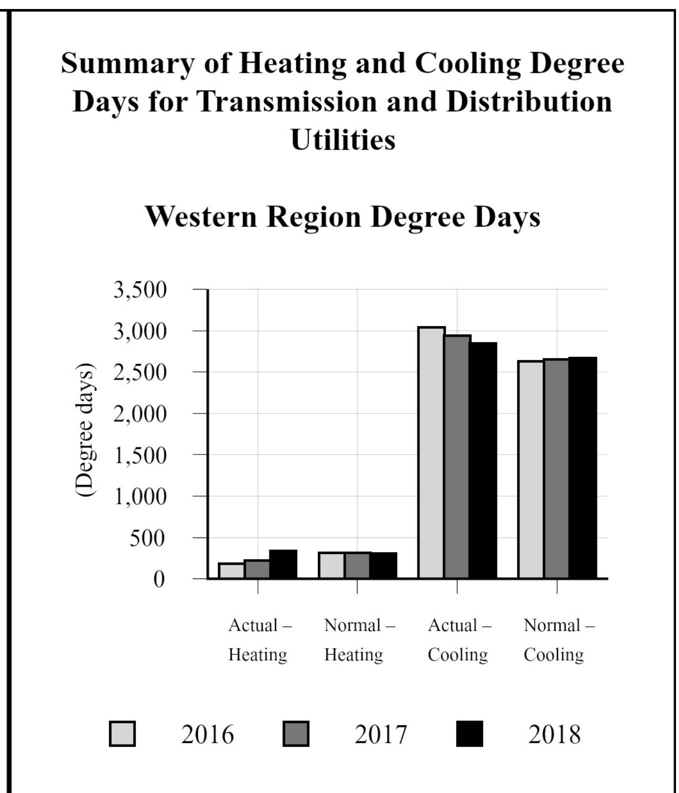
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

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

	Years Ended December 31,		
	2018	2017	2016
	(in degree days)		
Eastern Region			
Actual – Heating (a)	3,357	2,709	2,957
Normal – Heating (b)	3,215	3,225	3,245
Actual – Cooling (c)	1,402	1,002	1,248
Normal – Cooling (b)	980	974	969
Western Region			
Actual – Heating (a)	354	239	201
Normal – Heating (b)	325	330	328
Actual – Cooling (d)	2,861	2,950	3,058
Normal – Cooling (b)	2,688	2,669	2,648

(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.





2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2017	$	636.4
Changes in Gross Margin:		
Retail Margins		152.2
Off-system Sales		63.3
Transmission Revenues		(1.6)
Other Revenues		2.2
Total Change in Gross Margin		216.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(342.4)
Depreciation and Amortization		(66.6)
Taxes Other Than Income Taxes		(31.6)
Interest and Investment Income		(3.5)
Carrying Costs Income		(1.9)
Allowance for Equity Funds Used During Construction		16.7
Non-Service Cost Component of Net Periodic Benefit Cost		23.4
Interest Expense		(4.0)
Total Change in Expenses and Other		(409.9)
Income Tax Expense		84.8
Year Ended December 31, 2018	$	527.4

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 $152 million primarily due to the following:
  - A $173 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 $77 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 $16 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.
  - A $10 million increase in Texas revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was offset by an increase in Other Operation and Maintenance expenses below.
  - A $10 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh in Ohio. This increase was offset by a corresponding increase in Taxes Other Than Income Taxes below.

  These increases were partially offset by:
  - A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense below.
  - A $42 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $41 million decrease in Ohio due to prior year over-recoveries and 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 $63 million primarily due to the following:
  - A $41 million increase due to prior year over-recoveries and 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.
  - A $22 million increase due to higher affiliated PPA revenues in Texas, which were partially offset by a corresponding increase in Other Operation and Maintenance expenses below.
- **Transmission Revenues** decreased $2 million primarily due to the following:
  - An $11 million decrease due to the 2018 provisions for customer refunds in Texas due to Tax Reform. This decrease was offset in Income Tax Expense below.
  - An $11 million decrease due to lower rates in Texas in order to pass the benefits of Tax Reform on to customers. This decrease was offset in Income Tax Expense below.
  - A $10 million decrease in Ohio primarily due to the 2018 provisions for customer refunds due to Tax Reform, partially offset by increased revenues due to additional transmission investments. This decrease was offset in Income Tax Expense below.

  These decreases were offset by:
  - A $30 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 $342 million primarily due to the following:
  - A $226 million increase primarily in transmission expenses that were fully recovered in rate riders/trackers within Gross Margins above.
  - A $77 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
  - A $19 million increase in affiliated PPA expenses in Texas. This increase was offset by an increase in Margins from Off-system sales above.

  These increases were partially offset by:
  - A $58 million decrease in Ohio PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- **Depreciation and Amortization** expenses increased $67 million primarily due to the following:
  - A $40 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $9 million increase in securitization amortizations related to Transition Funding in Texas. This increase was offset in Other Revenues and Interest Expense.
  - An $8 million increase in amortization due to capitalized software.
- **Taxes Other Than Income Taxes** increased $32 million primarily due to the following:
  - An $18 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
  - A $12 million increase in rider revenues recovering state excise taxes due to an increase in metered KWhs. This increase was offset in Retail Margins above.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to increased transmission projects in Texas.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $23 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Income Tax Expense** decreased $85 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income, partially offset by the benefit related to the remeasurement of deferred tax liabilities recognized in 2017 as a result of Tax Reform.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2016	$ 482.1
Changes in Gross Margin:	
Retail Margins	(25.7)
Off-system Sales	(83.8)
Transmission Revenues	32.3
Other Revenues	6.9
Total Change in Gross Margin	(70.3)
Changes in Expenses and Other:	
Other Operation and Maintenance	196.1
Depreciation and Amortization	(17.6)
Taxes Other Than Income Taxes	(19.4)
Interest and Investment Income	(7.1)
Carrying Costs Income	(16.4)
Allowance for Equity Funds Used During Construction	(1.9)
Non-Service Cost Component of Net Periodic Benefit Cost	0.2
Interest Expense	12.8
Total Change in Expenses and Other	146.7
Income Tax Expense	77.9
Year Ended December 31, 2017	$ 636.4

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

- **Retail Margins** decreased $26 million primarily due to the following:
  - A $178 million decrease in Ohio revenues associated with the Universal Service Fund (USF) surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operating and Maintenance expenses below.
  - An $83 million decrease due to the impact of a 2016 regulatory deferral of capacity costs related to OPCo's December 2016 Global Settlement.
  - A $23 million net decrease in recovery of equity carrying charges related to the PIRR in Ohio, net of associated amortizations.
  - A $21 million decrease in revenues associated with smart grid riders in Ohio. This decrease was offset in various expense items below.
  - A $15 million decrease in weather-normalized margins, primarily in the residential class.
  - A $9 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues and associated deferrals in Ohio. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - A $7 million decrease in state excise taxes due to a decrease in metered KWh in Ohio. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes.

  These decreases were partially offset by:
  - A $150 million net increase due to the impact of 2016 provisions for refund primarily related to OPCo’s December 2016 Global Settlement.

- A $62 million increase in Ohio due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net margin related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- A $45 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
- A $31 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was offset by a corresponding increase in Other Operation and Maintenance below.
- A $16 million net increase in Ohio RSR revenues less associated amortizations.
- A $7 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in other expense items below.

- **Margins from Off-system Sales** decreased $84 million primarily due to the following:
  - A $62 million decrease in Ohio due to current year losses from a power contract with OVEC, which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
  - A $41 million decrease in Ohio due to the 2016 reversal of prior year provisions for regulatory loss.

  This decrease was partially offset by:
  - An $18 million increase in Ohio primarily due to the impact of prior year losses from a power contract with OVEC which was not included in the OVEC PPA rider.
- **Transmission Revenues** increased $32 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $7 million primarily due the following:
  - A $12 million increase in securitization revenue in Texas. This increase was offset below in Depreciation and Amortization and in Interest Expense.

  This increase was partially offset by:
  - A $4 million decrease in Texas performance bonus revenues and true-ups related to energy efficiency programs.

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

- **Other Operation and Maintenance** expenses decreased $196 million primarily due to the following:
  - A $178 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $29 million decrease primarily due to charitable donations in 2016, including the AEP Foundation.
  - A $17 million decrease in employee-related expenses.

  These decreases were partially offset by:
  - A $19 million increase in recoverable expenses primarily in PJM as well as increased ERCOT transmission expenses, partially offset by energy efficiency expenses that were fully recovered in rate recovery riders/trackers within Gross Margins above.
  - A $14 million increase in PJM expenses related to the annual formula rate true-up that will be recovered in 2018.
  - A $6 million increase in non-deferred storm expenses, primarily in the Texas region.
- **Depreciation and Amortization** expenses increased $18 million primarily due to the following:
  - A $21 million increase due to securitization amortizations related to Texas securitized transition funding. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $15 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - An $8 million increase due to amortization of capitalized software costs.

  These increases were partially offset by:
  - An $8 million decrease due to recoveries of transmission cost rider carrying costs in Ohio. This decrease was partially offset in Retail Margins above.
  - An $8 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $7 million decrease in recoverable smart grid rider depreciation expenses in Ohio. This decrease was partially offset in Retail Margins above.

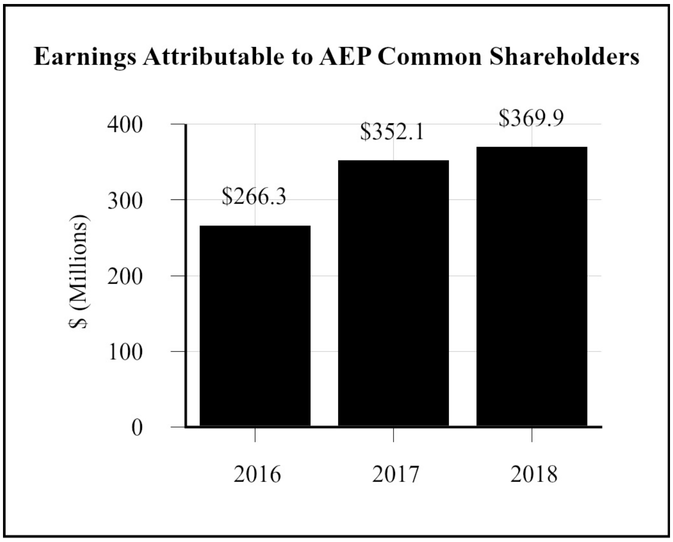
- **Taxes Other Than Income Taxes** increased $19 million primarily due to the following:
  - A $26 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

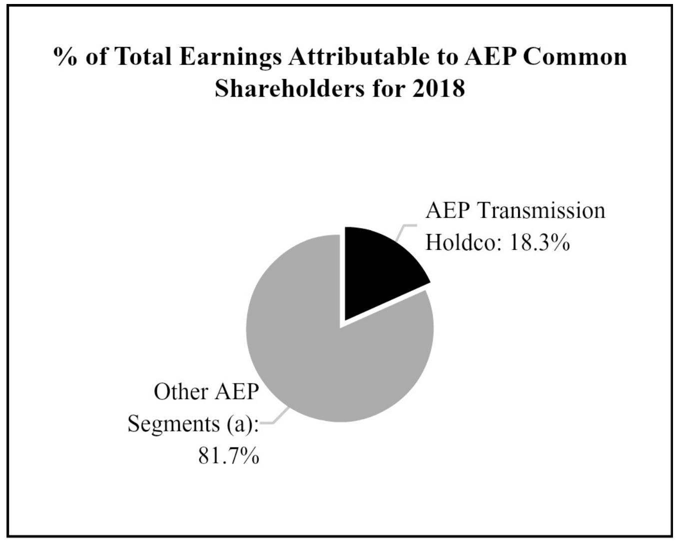
  This increase was partially offset by:
  - A $7 million decrease in state excise taxes due to a decrease in metered KWhs in Ohio. This decrease was offset in Retail Margins above.
- **Interest and Investment Income** decreased $7 million primarily due to a prior year tax adjustment in Texas.
- **Carrying Costs Income** decreased $16 million primarily due to the impact of a 2016 regulatory deferral of capacity related carrying costs in Ohio.
- **Interest Expense** decreased $13 million primarily due to the following:
  - A $10 million decrease primarily due to the maturity of a senior unsecured note in June 2016 in Ohio.
  - A $9 million decrease in the Texas securitization transition assets due to the final maturity of the first Texas securitization bond. This decrease was offset above in Other Revenues and in Depreciation and Amortization.

  These decreases were partially offset by:
  - A $7 million increase due to the issuance of long-term debt in September 2017 in Texas.
- **Income Tax Expense** decreased $78 million primarily due to the following:
  - A $138 million decrease due to the recording of federal income tax adjustments related to Tax Reform.

  This decrease was partially offset by:
  - A $60 million increase in pretax book income and by the recording of federal and state income tax adjustments.

AEP TRANSMISSION HOLDCO





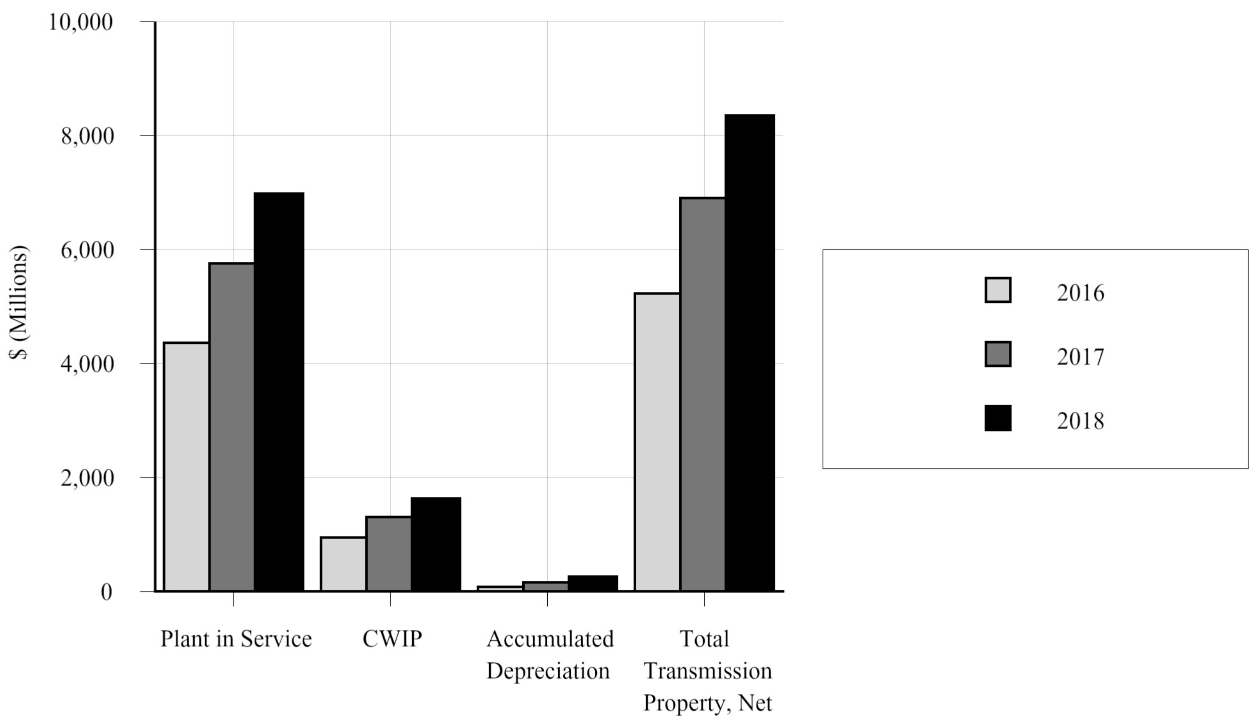
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

AEP Transmission Holdco	Years Ended December 31, 2018	2017	2016
		(in millions)	
Transmission Revenues	$ 804.1	$ 766.7	$ 512.8
Other Operation and Maintenance	105.6	74.7	55.5
Depreciation and Amortization	137.8	102.2	67.1
Taxes Other Than Income Taxes	142.3	114.0	88.7
Operating Income	418.4	475.8	301.5
Interest and Investment Income	2.5	1.2	0.4
Carrying Costs Expense	(0.4)	(0.2)	(0.3)
Allowance for Equity Funds Used During Construction	67.2	52.5	52.2
Non-Service Cost Components of Net Periodic Benefit Cost	2.6	0.3	0.2
Interest Expense	(90.7)	(72.8)	(50.3)
Income Before Income Tax Expense and Equity Earnings	399.6	456.8	303.7
Income Tax Expense	95.3	189.8	134.1
Equity Earnings of Unconsolidated Subsidiaries	68.7	88.6	99.7
Net Income	373.0	355.6	269.3
Net Income Attributable to Noncontrolling Interests	3.1	3.5	3.0
Earnings Attributable to AEP Common Shareholders	$ 369.9	$ 352.1	$ 266.3

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2018	December 31, 2017	December 31, 2016
	(in millions)		
Plant in Service	$ 7,008.4	$ 5,784.6	$ 4,386.0
Construction Work in Progress	1,651.1	1,325.6	968.0
Accumulated Depreciation and Amortization	282.8	176.6	101.4
Total Transmission Property, Net	$ 8,376.7	$ 6,933.6	$ 5,252.6

AEPTHC's Investment in Transmission Assets



2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2017	$	352.1
Changes in Transmission Revenues:		
Transmission Revenues		37.4
Total Change in Transmission Revenues		37.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(30.9)
Depreciation and Amortization		(35.6)
Taxes Other Than Income Taxes		(28.3)
Interest and Investment Income		1.3
Carrying Costs Expense		(0.2)
Allowance for Equity Funds Used During Construction		14.7
Non-Service Cost Components of Net Periodic Pension Cost		2.3
Interest Expense		(17.9)
Total Change in Expenses and Other		(94.6)
Income Tax Expense		94.5
Equity Earnings of Unconsolidated Subsidiaries		(19.9)
Net Income Attributable to Noncontrolling Interests		0.4
Year Ended December 31, 2018	$	369.9

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

- **Transmission Revenues** increased $37 million primarily due to:
  - A $101 million increase in revenues driven by an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

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

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

- **Other Operation and Maintenance** expenses increased $31 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $36 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- **Interest Expense** increased $18 million primarily due to the following:
  - A $23 million increase primarily due to higher long-term debt balances.

  This increase was partially offset by:
  - A $5 million decrease due to higher AFUDC borrowed funds resulting from a higher CWIP balance.

- **Income Tax Expense** decreased $95 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $20 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.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2016	$	266.3
Changes in Transmission Revenues:		
Transmission Revenues		253.9
Total Change in Transmission Revenues		253.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(19.2)
Depreciation and Amortization		(35.1)
Taxes Other Than Income Taxes		(25.3)
Interest and Investment Income		0.8
Carrying Costs Expense		0.1
Allowance for Equity Funds Used During Construction		0.3
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(22.5)
Total Change in Expenses and Other		(100.8)
Income Tax Expense		(55.7)
Equity Earnings of Unconsolidated Subsidiaries		(11.1)
Net Income Attributable to Noncontrolling Interests		(0.5)
Year Ended December 31, 2017	$	352.1

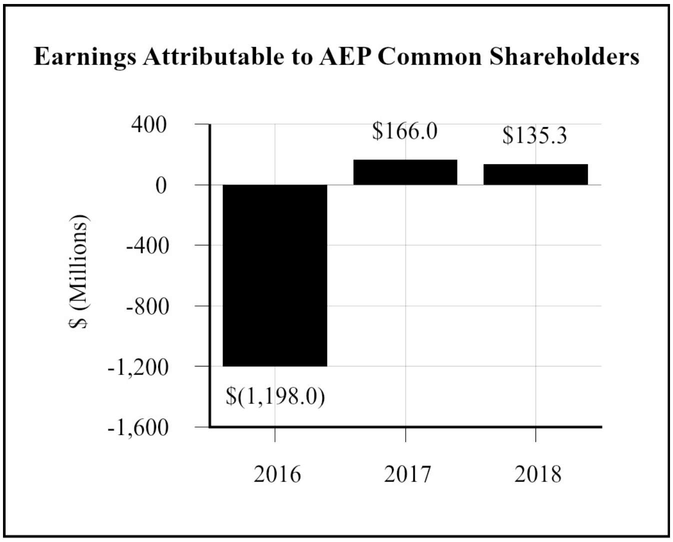
The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates were as follows:

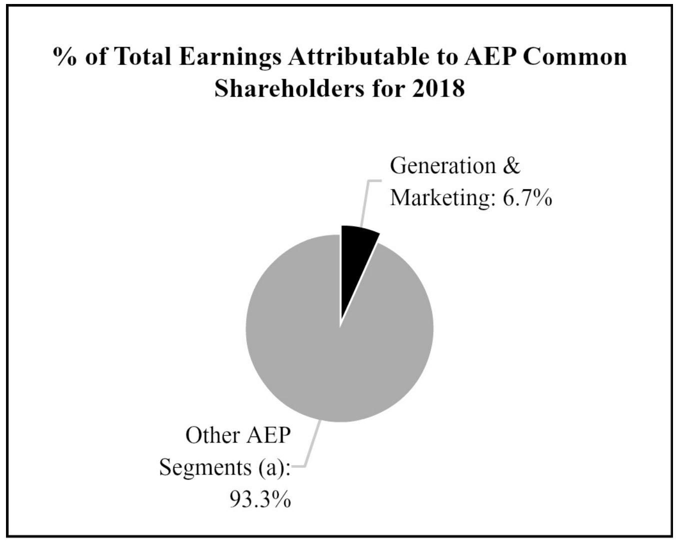
- **Transmission Revenues** increased $254 million primarily due to:
  - A $246 million increase in formula rates driven by the favorable impact of the modification of the PJM OATT formula combined with an increase driven by continued investments in transmission assets.
  - A $7 million increase due to rental revenue related to various AEPTCo facilities.

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

- **Other Operation and Maintenance** expenses increased $19 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $35 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $25 million primarily due to increased property taxes as a result of additional transmission investment.
- **Interest Expense** increased $23 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $56 million primarily due to an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $11 million primarily due to lower earnings at ETT resulting from increased property taxes, depreciation expense, and decreased AFUDC, partially offset by increased revenues. The revenue increase is primarily due to interim rate increases in the third quarter of 2016 and higher loads, partially offset by an ETT rate reduction that went into effect in March 2017.

GENERATION & MARKETING



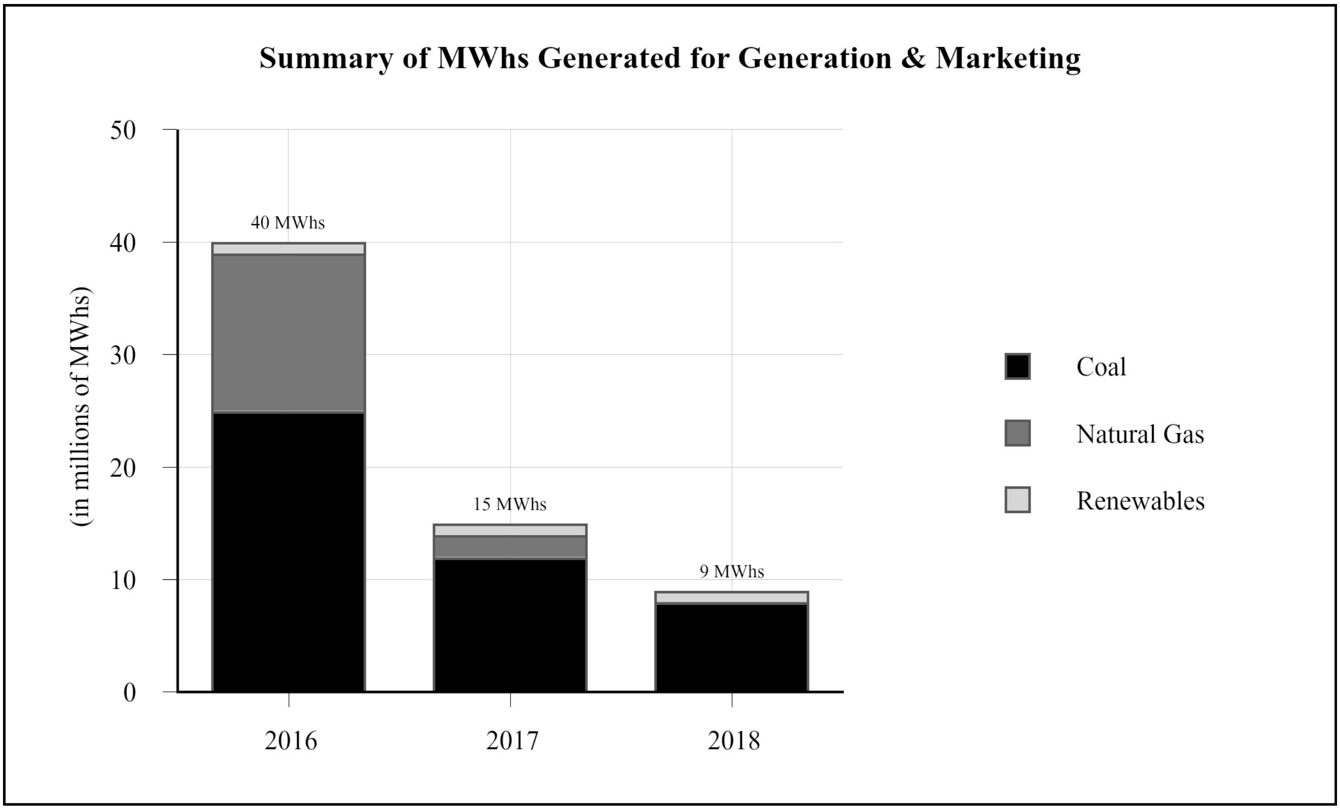


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Generation & Marketing	Years Ended December 31, 2018	2017	2016
		(in millions)	
Revenues	$ 1,940.3	$ 1,875.1	$ 2,986.0
Fuel, Purchased Electricity and Other	1,537.3	1,377.2	1,948.6
Gross Margin	403.0	497.9	1,037.4
Other Operation and Maintenance	229.3	279.5	426.5
Asset Impairments and Other Related Charges	47.7	53.5	2,257.3
Gain on Sale of Merchant Generation Assets	—	(226.4)	—
Depreciation and Amortization	41.0	24.2	154.6
Taxes Other Than Income Taxes	13.4	12.1	37.6
Operating Income (Loss)	71.6	355.0	(1,838.6)
Interest and Investment Income	13.1	10.3	1.4
Allowance for Equity Funds Used During Construction	—	—	0.4
Non-Service Cost Components of Net Periodic Benefit Cost	15.2	8.9	8.1
Interest Expense	(14.9)	(18.5)	(35.8)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings	85.0	355.7	(1,864.5)
Income Tax Expense (Benefit)	(49.2)	189.7	(666.5)
Equity Earnings of Unconsolidated Subsidiaries	0.5	—	—
Net Income (Loss)	134.7	166.0	(1,198.0)
Net Loss Attributable to Noncontrolling Interests	(0.6)	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$ 135.3	$ 166.0	$ (1,198.0)

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31,		
	2018	2017	2016
	(in millions of MWhs)		
Fuel Type:			
Coal	8	12	25
Natural Gas	—	2	14
Renewables	1	1	1
Total MWhs	9	15	40



2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2017	$	166.0
Changes in Gross Margin:		
Generation		(85.8)
Retail, Trading and Marketing		(20.9)
Other		11.8
Total Change in Gross Margin		(94.9)
Changes in Expenses and Other:		
Other Operation and Maintenance		50.2
Asset Impairments and Other Related Charges		5.8
Gain on Sale of Merchant Generation Assets		(226.4)
Depreciation and Amortization		(16.8)
Taxes Other Than Income Taxes		(1.3)
Interest and Investment Income		2.8
Non-Service Cost Components of Net Periodic Benefit Cost		6.3
Interest Expense		3.6
Total Change in Expenses and Other		(175.8)
Income Tax Expense (Benefit)		238.9
Equity Earnings of Unconsolidated Subsidiaries		0.5
Net Loss Attributable to Noncontrolling Interests		0.6
Year Ended December 31, 2018	$	135.3

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

- **Generation** decreased $86 million primarily due to reduced energy margins in 2018 and the reduction of revenues associated with the sale of certain merchant generation assets in 2017.
- **Retail, Trading and Marketing** decreased $21 million primarily due to lower retail margins due to higher market costs and increased competition combined with decreased marketing volumes in 2018.
- **Other Revenue** increased $12 million primarily due to renewable projects placed in-service.

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

- **Other Operation and Maintenance** expenses decreased $50 million primarily due to the following:
  - A $38 million decrease in the Stuart Plant asset retirement obligation.
  - A $24 million decrease in expenses due to the closure of the Stuart Plant in 2018.
  - A $9 million decrease in expenses due to the sale of merchant generation assets in 2017.

  These decreases were partially offset by:
  - A $17 million increase due to severance accruals related to announced merchant generation plant retirements.
- **Asset Impairments and Other Related Charges** decreased $6 million primarily due to an $8 million decrease in impairment charges related to Racine partially offset by a $2 million increase in impairment charges related to merchant coal-fired generation assets in 2017.
- **Gain on Sale of Merchant Generation Assets** decreased $226 million due to the sale of certain merchant generation assets in 2017.

- **Depreciation and Amortization** expenses increased $17 million primarily due to a higher depreciable base from increased investments in renewable energy sources.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $6 million primarily due to favorable asset returns for funded Pension and OPEB plans, favorable OPEB cost savings arrangement and the implementation of ASU 2017-07.
- **Income Tax Expense (Benefit)** decreased $239 million primarily due to a decrease in pretax book income driven by the gain on sale of certain merchant generation assets in 2017, the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and the utilization of a $47 million tax capital loss benefit.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2016	$ (1,198.0)
Changes in Gross Margin:	
Generation	(504.8)
Retail, Trading and Marketing	(48.5)
Other	13.8
Total Change in Gross Margin	(539.5)
Changes in Expenses and Other:	
Other Operation and Maintenance	147.0
Asset Impairments and Other Related Charges	2,203.8
Gain on Sale of Merchant Generation Assets	226.4
Depreciation and Amortization	130.4
Taxes Other Than Income Taxes	25.5
Interest and Investment Income	8.9
Allowance for Equity Funds Used During Construction	(0.4)
Non-Service Cost Components of Net Periodic Benefit Cost	0.8
Interest Expense	17.3
Total Change in Expenses and Other	2,759.7
Income Tax Expense (Benefit)	(856.2)
Year Ended December 31, 2017	$ 166.0

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 $505 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- **Retail, Trading and Marketing** decreased $49 million primarily due to lower retail margins in 2017 combined with the impact of favorable wholesale trading and marketing performance in 2016.
- **Other Revenue** increased $14 million primarily due to renewable projects placed in-service.

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

- **Other Operation and Maintenance** expenses decreased $147 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- **Asset Impairments and Other Related Charges** decreased $2.2 billion due to the impairment of certain merchant generation assets in 2016, partially offset by a $43 million impairment of Racine in 2017.
- **Gain on Sale of Merchant Generation Assets** increased $226 million due to the sale of certain merchant generation assets.
- **Depreciation and Amortization** expenses decreased $130 million primarily due to the sale and impairment of certain merchant generation assets.
- **Taxes Other Than Income Taxes** decreased $26 million primarily due to the sale of certain merchant generation assets.
- **Interest and Investment Income** increased $9 million primarily due to additional cash invested as a result of the sale of certain merchant generation assets.

- **Interest Expense** decreased $17 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.
- **Income Tax Expense (Benefit)** increased $856 million primarily due to an increase in pretax book income as a result of the impairment of certain merchant generation assets recorded in 2016, a gain on the sale of certain merchant generation assets recorded in 2017 and the recording of federal income tax adjustments related to Tax Reform.

CORPORATE AND OTHER

2018 Compared to 2017

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $32 million in 2017 to a loss of $99 million in 2018 primarily due to:

- A $59 million increase in interest expense as a result of increased debt outstanding.
- A $26 million decrease in business development and other revenues.
- A $20 million impairment of an equity investment and related assets in 2018.
- A $12 million gain recognized on the sale of an equity investment in the third quarter of 2017.

These items were partially offset by:

- A $21 million decrease in general corporate expenses.
- A $16 million decrease in income tax expense primarily related to an $18 million favorable impact resulting from the enactment of Kentucky state tax legislation in the second quarter of 2018, 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. These decreases were partially offset by a $47 million tax capital loss benefit allocated to the Generation & Marketing segment.

2017 Compared to 2016

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from $81 million in 2016 to a loss of $32 million in 2017 primarily due to the prior year reversal of capital loss valuation allowances related to effectively settling a 2011 audit issue with the IRS and the impact of the pending sale of certain merchant generation assets as well as 2015 tax return adjustments related to the disposition of AEP's commercial barging operations. Earnings attributable to AEP Common Shareholders also decreased due to increased income tax expense in 2017 as a result of federal income tax adjustments related to Tax Reform. These decreases were offset by an increase in pretax book income primarily due to lower operating expenses.

AEP SYSTEM INCOME TAXES

2018 Compared to 2017

Income Tax Expense decreased $854 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

2017 Compared to 2016

Income Tax Expense increased $1 billion primarily due to an increase in pretax book income in 2017 driven by the impairment of certain merchant generation assets in 2016. The increase in Income Tax Expense is also due to the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets, the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS as well as 2015 tax return adjustments recorded in 2016 related to the disposition of AEP's commercial barging operations.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2018		2017	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 23,346.7	52.7%	$ 21,173.3	51.5%
Short-term Debt	1,910.0	4.3	1,638.6	4.0
Total Debt	25,256.7	57.0	22,811.9	55.5
AEP Common Equity	19,028.4	42.9	18,287.0	44.4
Noncontrolling Interests	31.0	0.1	26.6	0.1
Total Debt and Equity Capitalization	$ 44,316.1	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 57.0% as of December 31, 2018 primarily due to an increase in debt to support increased 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 December 31, 2018, AEP had a $4 billion revolving credit facility to support its commercial paper program. 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-and-leaseback or leasing agreements or common stock.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2018, available liquidity was $3.1 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 4,000.0	June 2022
Cash and Cash Equivalents	234.1	
Total Liquidity Sources	4,234.1	
Less: AEP Commercial Paper Outstanding	1,160.0	
Net Available Liquidity	$ 3,074.1	

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during 2018 was $2.3 billion. The weighted-average interest rate for AEP's commercial paper during 2018 was 2.33%.

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 December 31, 2018, were $61 million with maturities ranging from January 2019 to December 2019.

Financing Plan

As of December 31, 2018, AEP had $1.7 billion of long-term debt due within one year. This included $457 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current and $400 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the other maturities due within one year on a long-term basis.

Securitized Accounts Receivables

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

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2018, this contractually-defined percentage was 55.4%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its credit agreements.

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

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

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.67 per share in January 2019. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 14 for additional information.

Credit Ratings

AEP and its utility subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but its access to the commercial paper market may depend on its credit ratings. In addition, downgrades in AEP's credit ratings by one of the rating agencies could increase its borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject AEP to additional collateral demands under adequate assurance clauses under its derivative and non-derivative energy contracts.

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders. AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 412.6	$ 403.5	$ 426.9
Net Cash Flows from Continuing Operating Activities	5,223.2	4,270.4	4,521.8
Net Cash Flows Used for Continuing Investing Activities	(6,353.6)	(3,656.4)	(5,046.6)
Net Cash Flows from (Used for) Continuing Financing Activities	1,161.9	(604.9)	503.9
Net Cash Flows from (Used for) Discontinued Operations	—	—	(2.5)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	31.5	9.1	(23.4)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 444.1	$ 412.6	$ 403.5

Operating Activities

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Income from Continuing Operations	$ 1,931.3	$ 1,928.9	$ 620.5
Non-Cash Adjustments to Income from Continuing Operations (a)	2,400.0	2,822.6	4,217.1
Mark-to-Market of Risk Management Contracts	(66.4)	(23.3)	150.8
Pension Contributions to Qualified Plant Trust	—	(93.3)	(84.8)
Property Taxes	(59.1)	(29.5)	(19.0)
Deferred Fuel Over/Under Recovery, Net	189.7	84.4	(65.5)
Recovery of Ohio Capacity Costs, Net	67.7	83.2	88.1
Provision for Refund - Global Settlement, Net	(5.5)	(98.2)	120.3
Disposition of Tanners Creek Plant Site	—	—	(93.5)
Change in Other Noncurrent Assets	119.8	(423.9)	(454.6)
Change in Other Noncurrent Liabilities	129.0	181.7	15.4
Change in Certain Components of Continuing Working Capital	516.7	(162.2)	27.0
Net Cash Flows from Continuing Operating Activities	$ 5,223.2	$ 4,270.4	$ 4,521.8

(a) Non-Cash Adjustments to Income from Continuing Operations includes Depreciation and Amortization, Deferred Income Taxes, Asset Impairments and Other Related Charges, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel, Pension and Postemployment Benefit Reserves, and Gain on Sale of Merchant Generation Assets.

2018 Compared to 2017

Net Cash Flows from Continuing Operating Activities increased by $953 million primarily due to the following:

- A $679 million increase in cash from Changes in Certain Components of Continuing Working Capital. This increase is primarily due to lower employee-related payments, increased accrued taxes, increased provisions for refund related to Tax Reform and timing of receivables and payables.
- A $544 million increase in Noncurrent Assets primarily due to changes in regulatory assets as a result of fewer storm deferrals, the impact of the FERC settlement on regulated AEP subsidiaries with rider recovery mechanisms in addition to the settlement of certain regulatory assets as a result of Ohio and West Virginia jurisdictional orders related to Tax Reform. See Note 4 - Rate Matters for additional information.
- A $105 million increase in cash from Deferred Fuel Over/Under Recovery, Net primarily due to fluctuations of fuel and purchase power costs at PSO and I&M and the reduction of ENEC balances at APCo and WPCo as a result of the West Virginia Tax Reform Order. See Note 4 - Rate Matters for additional information relating to the reduction of ENEC balances.
- A $93 million increase in cash due to refunds to customers in 2017 as a result of the 2016 Global Settlement in Ohio.
- A $93 million increase in cash due to Pension Contributions to Qualified Plan Trust in 2017 not made in 2018.

These increases in cash were partially offset by:

- A $420 million decrease in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for further detail.

2017 Compared to 2016

Net Cash Flows from Continuing Operating Activities decreased by $251 million primarily due to the following:

- A $189 million decrease in cash from Changes in Certain Components of Continuing Working Capital. This decrease in cash is primarily due to higher employee-related payments and increased revenue refunds.
- A $98 million decrease in cash due to refunds to customers as a result of the 2016 Global Settlement in Ohio.
- An $86 million decrease in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for further detail.

These decreases in cash were partially offset by:

- A $150 million increase in cash from Deferred Fuel Over/Under Recovery, Net. The increase in cash is primarily due to fluctuations of fuel and purchase power costs at PSO and collections in the Ohio Phase-in-Recovery Rider.

Investing Activities

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Construction Expenditures	$ (6,310.9)	$ (5,691.3)	$ (4,781.1)
Acquisitions of Nuclear Fuel	(46.1)	(108.0)	(128.5)
Acquisitions of Assets/Businesses	(14.6)	(6.8)	(107.9)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6	—
Other	18.0	(9.9)	(29.1)
Net Cash Flows Used for Continuing Investing Activities	$ (6,353.6)	$ (3,656.4)	$ (5,046.6)

2018 Compared to 2017

Net Cash Flows Used for Continuing Investing Activities increased by $2.7 billion primarily due to the following:

- A $2.2 billion decrease in cash due to the sale of certain merchant generation assets in 2017. See Note 7 - Dispositions and Impairments for additional information.
- A $620 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $598 million.

These increases in cash were partially offset by:

- $62 million increase in cash due to reduced nuclear fuel purchases. The reduction in purchases is primarily due to variations from year to year in the timing and pricing of fuel reload requirements, material and services deliveries and the timing of cash payments during the nuclear fuel cycle.

2017 Compared to 2016

Net Cash Flows Used for Continuing Investing Activities decreased by $1.4 billion primarily due to the following:

- A $2.2 billion increase in cash due to the sale of certain merchant generation assets in 2017. See Note 7 - Dispositions and Impairments for additional information.
- A $101 million increase in cash primarily due to lower cost of acquisitions in 2017.
- A $21 million increase in cash due to reduced nuclear fuel purchases. Reduction in purchases is primarily due to variations from year to year in the timing and pricing of fuel reload requirements, material and services deliveries, and the timing of cash payments during the nuclear fuel cycle.

These increases in cash were partially offset by:

- A $910 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $499 million, AEP Transmission Holdco of $275 million and Generation & Marketing of $95 million.

Financing Activities

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Issuance of Common Stock	$ 73.6	$ 12.2	$ 34.2
Issuance/Retirement of Debt, Net	2,435.1	691.8	1,713.0
Dividends Paid on Common Stock	(1,255.5)	(1,191.9)	(1,121.0)
Other	(91.3)	(117.0)	(122.3)
Net Cash Flows from (Used for) Continuing Financing Activities	$ 1,161.9	$ (604.9)	$ 503.9

2018 Compared to 2017

Net Cash Flows from Continuing Financing Activities increased by $1.8 billion primarily due to the following:

- A $1.1 billion increase in cash due to increased issuances of long-term debt. See Note 14 - Financing Activities for additional information.
- A $346 million increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 14 - Financing Activities for additional information.
- A $306 million increase in cash due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $61 million increase in cash due to increased proceeds from issuances of common stock.

These increases in cash were partially offset by:

- A $64 million decrease in cash due to increased common stock dividend payments primarily due to increased dividends per share from 2017 to 2018.

2017 Compared to 2016

Net Cash Flows Used for Continuing Financing Activities increased by $1.1 billion primarily due to the following:

- A $1.3 billion decrease in cash due to increased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $987 million decrease in cash from short-term debt primarily due to increased repayments of commercial paper. See Note 14 - Financing Activities for additional information.
- A $71 million decrease in cash due to increased common stock dividend payments primarily due to increased dividends per share from 2016 to 2017.
- A $22 million decrease in cash due to reduced proceeds from issuances of common stock.

These decreases in cash were partially offset by:

- A $1.3 billion increase in cash due to increased issuances of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2018:

AEP Common Stock:

- During 2018, AEP issued 1.2 million shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $74 million.

Debt:

- During 2018, AEP issued approximately $5 billion of long-term debt, including $4.1 billion of senior unsecured notes at interest rates ranging from 3.65% to 4.3%, $369 million of pollution control bonds at interest rates ranging from 2.625% to 3.05% and $550 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2018, AEP entered into and settled $300 million of notional interest rate derivatives that were designated as cash flow hedges. The settlement of interest rate derivatives in 2018 resulted in net cash received of $4 million. As of December 31, 2018, AEP had $500 million of notional interest rate derivatives remaining that were designated as fair value hedges.

In 2019:

In January and February 2019, I&M retired $15 million and $2 million, respectively, of Notes Payable related to DCC Fuel.

In January and February 2019, Transource Energy issued $3 million and $3 million, respectively, of variable rate Other Long-term Debt due in 2020.

In January 2019, AEP Texas retired $104 million of Securitization Bonds.

In January 2019, OPCo retired $23 million of Securitization Bonds.

In January 2019, SWEPCo retired $54 million of 1.60% Pollution Control Bonds due in 2019.

In February 2019, APCo retired $12 million of Securitization Bonds.

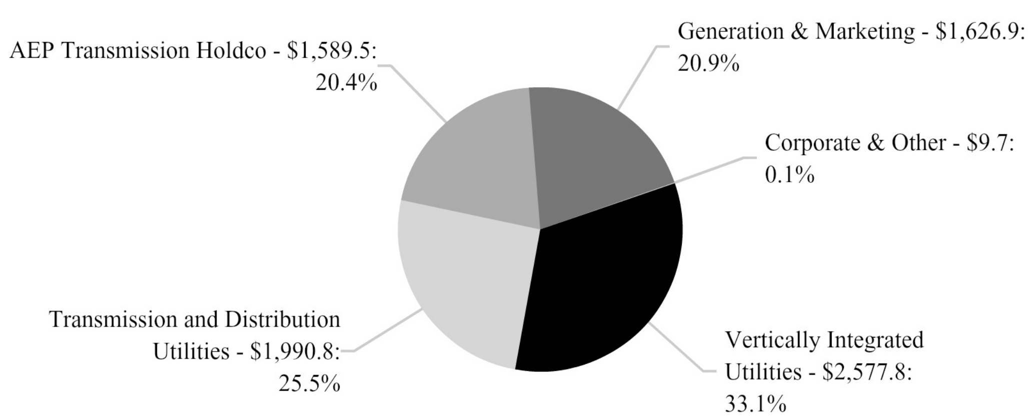
BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.8 billion of capital expenditures in 2019. For the four year period, 2020 through 2023, management forecasts capital expenditures of $25.1 billion. The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital 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 capital 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. The 2019 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2019 Budgeted Capital Expenditures					
Segment	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
Vertically Integrated Utilities	$ 222.7	$ 383.1	$ 727.1	$ 972.3	$ 272.6	$ 2,577.8
Transmission and Distribution Utilities	0.1	2.4	994.1	781.1	213.1	1,990.8
AEP Transmission Holdco	—	—	1,546.4	—	43.1	1,589.5
Generation & Marketing	15.0	1,557.6 (b)	—	—	54.3	1,626.9
Corporate and Other	—	—	—	—	9.7	9.7
Total	$ 237.8	$ 1,943.1	$ 3,267.6	$ 1,753.4	$ 592.8	$ 7,794.7

(a) Amount primarily consists of facilities, software and telecommunications.
(b) Amount includes $1.1 billion for the acquisition of Sempra Renewables LLC, which includes 724 MWs of wind generation and battery assets and is funded through $551 million in cash, assumption of $343 million of existing project debt obligations of the non-consolidated joint ventures and recognition of non-controlling tax equity interest of $162 million.

2019 Budgeted Capital Expenditures by Business Segment

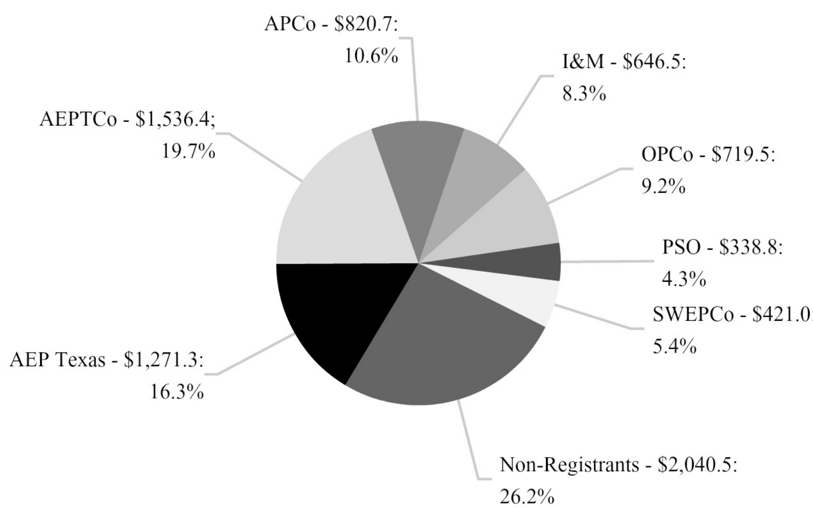


The 2019 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation related investments, as well as expenditures for compliance with environmental regulations as follows:

	2019 Budgeted Capital Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
AEP Texas	$ 0.1	$ 2.4	$ 785.4	$ 374.1	$ 109.3	$ 1,271.3
AEPTCo	—	—	1,496.6	—	39.8	1,536.4
APCo	32.7	83.5	309.8	304.2	90.5	820.7
I&M	76.8	179.8	96.5	229.8	63.6	646.5
OPCo	—	—	208.7	407.0	103.8	719.5
PSO	2.5	31.1	62.7	194.2	48.3	338.8
SWEPCo	25.1	57.7	150.7	135.4	52.1	421.0

(a) Amount primarily consists of facilities, software and telecommunications.

2019 Budgeted Capital Expenditures by Registrant Subsidiary



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.

Rockport Plant, Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M were $295 million each as of December 31, 2018.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. AEP's subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13 - Leases. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, as well as AEP's subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt. See "Rockport Plant Litigation" section of Note 6 for additional information.

CONTRACTUAL OBLIGATION INFORMATION

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations as of December 31, 2018 and does not reflect AEP's planned 2019 acquisition of Sempra Renewables, LLC. See "Other Renewable Generation" section of Executive Overview for additional information.

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 1,910.0	$ —	$ —	$ —	$ 1,910.0
Interest on Fixed Rate Portion of Long-term Debt (b)	1,030.3	1,955.9	1,719.2	11,189.0	15,894.4
Fixed Rate Portion of Long-term Debt (c)	924.4	2,800.0	2,128.2	16,150.9	22,003.5
Variable Rate Portion of Long-term Debt (d)	774.1	669.8	79.8	—	1,523.7
Capital Lease Obligations (e)	70.8	111.9	79.3	90.2	352.2
Noncancelable Operating Leases (e)	259.6	482.8	280.8	165.2	1,188.4
Fuel Purchase Contracts (f)	1,108.4	1,075.9	381.0	147.0	2,712.3
Energy and Capacity Purchase Contracts	239.7	463.6	324.3	1,337.2	2,364.8
Construction Contracts for Capital Assets (g)	2,429.1	3,127.6	1,679.9	3,245.0	10,481.6
Total	$ 8,746.4	$ 10,687.5	$ 6,672.5	$ 32,324.5	$ 58,430.9

(a) Represents principal only, excluding interest.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(c) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest.

(d) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 1.66% and 3.94% as of December 31, 2018.

(e) See Note 13 - Leases.

(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

(g) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

AEP's $18 million liability related to uncertain tax positions is not included above because management cannot reasonably estimate the cash flows by period.

AEP's pension funding requirements are not included in the above table. As of December 31, 2018, AEP expects to make contributions to the pension plans totaling $99 million in 2019. Estimated contributions of $105 million in 2020 and $108 million in 2021 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 97.6% funded as of December 31, 2018. See "Estimated Future Benefit Payments and Contributions" section of Note 8.

In addition to the amounts disclosed in the contractual cash obligations table above, additional commitments are made in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2018, the commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 60.6	$ —	$ —	$ —	$ 60.6
Guarantees of the Performance of Outside Parties (b)	—	—	—	140.0	140.0
Guarantees of Performance (c)	1,526.6	—	—	—	1,526.6
Total Commercial Commitments	$ 1,587.2	$ —	$ —	$ 140.0	$ 1,727.2

(a) 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. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any letters of credit are drawn, there is no recourse to third-parties. See "Letters of Credit" section of Note 6.

(b) See "Guarantees of Third-Party Obligations" section of Note 6.

(c) Performance guarantees and indemnifications issued for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, AEP recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, AEP continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and AEP will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

The IRS has proposed new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. Generally, AEP's regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in service after January 1, 2018 and AEP's competitive businesses will be eligible for 100% expensing. However, for self-constructed property and other property placed in service in 2018 for which construction began prior to January 1, 2018, taxpayers are required to evaluate the contractual terms to determine if these additions qualify for 100% expensing under Tax Reform or 50% bonus depreciation as provided under prior tax law.

During the fourth quarter of 2018, the IRS proposed new regulations that reflect changes as a result of Tax Reform concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide a de minimis test under which all interest is deductible if less than 10% is allocable to the competitive businesses. Management continues to review and evaluate the proposed regulations and at this time expect to be able to deduct materially all business interest expense under this de minimis provision.

Section 162(m) of the Internal Revenue Code generally limits the amount of compensation a company can deduct annually to $1 million for certain executive officers. The exemption from Section 162(m)'s deduction limit for performance-based compensation was repealed by Tax Reform, effective for taxable years ending after December 31, 2017. Management continues to evaluate whether any of its compensation plans qualify for transitional relief, such that payments made pursuant to these plans might be deductible.

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. The operations of AEP's electric utility subsidiaries are subject to extensive and rigorous mandatory cyber and physical security requirements that are developed and enforced by NERC to protect grid security and reliability. AEP's Enterprise Security program uses the National Institute of Standards and Technology Cybersecurity Framework as a guideline.

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 understanding of these events develop, AEP has adopted a defense in depth approach to cyber security and continually assesses its cyber security tools and processes to determine where to strengthen its defenses. These strategies include monitoring, alerting and emergency response, forensic analysis, disaster recovery and criminal activity reporting. This approach allows AEP to deal with threats in real time.

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 reviewed annually with the Board of Directors and at several meetings with the Audit Committee throughout the year. AEP's strategy for managing cyber related risks is integrated within its enterprise risk management processes. AEP enterprise security continually adjusts staff and resources in response to the evolving threat landscape. In addition, AEP maintains cyber liability insurance to cover certain damages caused by cyber incidents.

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, which includes cyber security. AEP operates a 24/7 Cyber Security Intelligence and Response Center (cyber security team) responsible for monitoring the AEP System for cyber risks and 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. AEP 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. AEP has implemented a third-party risk governance program to identify potential risks introduced through third-party relationships, such as vendors, software and hardware manufacturers or professional service providers. As warranted, AEP obtains certain contractual security guarantees and assurances with these third-party relationships to help ensure the security and safety of our information. 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 an active 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 continues to work with nonaffiliated entities to do penetration testing and to design and implement appropriate remediation strategies.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrants recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the timing of expense and income recognition is matched with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, regulatory assets are recorded on the balance sheet. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, regulatory liabilities are recorded when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. Refer to Note 5 - Effects of Regulation for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

AEP recognizes revenues from customers as the performance obligations of delivering energy to customers are satisfied. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. PSO and SWEPCo do not include the fuel portion in unbilled revenue in accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas.

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $255 million and $278 million as of December 31, 2018 and 2017, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $(23) million, $37 million and $50 million for the years ended December 31, 2018, 2017 and 2016, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $178 million and $202 million as of December 31, 2018 and 2017, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $(24) million, $11 million and $40 million for the years ended December 31, 2018, 2017 and 2016, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $59 million and $54 million as of December 31, 2018 and 2017, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $5 million, $5 million and $2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Assumptions and Approach Used

For each Registrant except AEPTCo, the monthly estimate for unbilled revenues is based upon a primary computation of net generation (generation plus purchases less sales) less the current month's billed KWh and estimated line losses, plus the prior month's unbilled KWh. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon an allocation of billed KWh to the current month and previous month, on a billing cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The two methodologies are evaluated to confirm that they are not statistically different.

For AEP's Generation & Marketing segment, management calculates unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect if Different Assumptions Used

If the two methodologies used to estimate unbilled revenue are statistically different, a limiter adjustment is made to bring the primary computation within one standard deviation of the secondary computation. Additionally, significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the estimate of unbilled revenue.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrants measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrants reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Note 10 - Derivatives and Hedging and Note 11 - Fair Value Measurements. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for AEP's fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. Such events or changes in circumstance include planned abandonments, probable disallowances for rate-making purposes of assets determined to be recently completed plant and assets that meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets.

An impairment evaluation of a long-lived, held and used asset may result from an abandonment, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount of the asset is not recoverable, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. Any impairment charge is recorded as a reduction to earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrants estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions on the use of the asset. The Registrants perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions are used in the applied valuation techniques. Estimates for depreciation rates contemplate the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, the timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and OPEB

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, AEP entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 - Benefit Plans for information regarding costs and assumptions for the Plans.

The following table shows the net periodic cost (credit) of the Plans:

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2018**	**2017**	**2016**
		(in millions)	
Pension Plans	$ 82.9	$ 98.6	$ 103.2
OPEB	(101.8)	(63.2)	(73.5)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2019, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 6.25% for the Qualified Plan and 6.25% for the OPEB plans.

The expected long-term rate of return on the Plans' assets is based on management's targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		OPEB	
	2019 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2019 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	25%	8.25%	49%	7.48%
Fixed Income	59	4.90	49	5.08
Other Investments	15	8.31	—	—
Cash and Cash Equivalents	1	2.50	2	2.50
Total	100%		100%	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 6.25% for both the Qualified Plan and OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual loss of 2.10% for the year ended December 31, 2018 and an actual gain of 12.86% for the year ended December 31, 2017. The OPEB plans' assets had an actual loss of 6.38% for the year ended December 31, 2018 and an actual gain of 18.38% for the year ended December 31, 2017. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2018, AEP had cumulative losses of approximately $173 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial losses may result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2018 under this method was 4.3% for the Qualified Plan, 4.2% for the Nonqualified Plans and 4.3% for the OPEB plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 6.25%, discount rates of 4.3% and 4.2% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $57 million, $67 million and $62 million in 2019, 2020 and 2021, respectively. Based on an expected rate of return on the OPEB plans' assets of 6.25%, a discount rate of 4.3% and various other assumptions, management estimates OPEB plan credits will approximate $81 million, $81 million and $83 million in 2019, 2020 and 2021, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets decreased to $4.7 billion as of December 31, 2018 from $5.2 billion as of December 31, 2017 primarily due to lower investment returns and benefit payments made in 2018. During 2018, the Qualified Plan paid $374 million and the Nonqualified Plans paid $11 million in benefits to plan participants. The value of AEP's OPEB plans' assets decreased to $1.5 billion as of December 31, 2018 from $1.7 billion as of December 31, 2017 primarily due to lower investment returns and benefit payments made in 2018. The OPEB plans paid $134 million in benefits to plan participants during 2018.

Nature of Estimates Required

AEP sponsors pension and OPEB plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and OPEB obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and OPEB expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2018 Benefit Obligations				
Discount Rate	$ (237.6)	$ 260.7	$ (59.4)	$ 65.3
Compensation Increase Rate	21.5	(19.7)	NA	NA
Cash Balance Crediting Rate	68.2	(63.3)	NA	NA
Health Care Cost Trend Rate	NA	NA	16.9	(15.7)
Effect on 2018 Periodic Cost				
Discount Rate	$ (13.4)	$ 14.6	$ (2.3)	$ 2.5
Compensation Increase Rate	5.6	(5.1)	NA	NA
Cash Balance Crediting Rate	14.3	(13.2)	NA	NA
Health Care Cost Trend Rate	NA	NA	2.1	(1.9)
Expected Return on Plan Assets	(24.2)	24.2	(8.5)	8.5

NA Not applicable.

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)
Year Ended December 31, 2018

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2017	$ 42.1	$ (131.3)	$ 163.9	$ 74.7
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(30.1)	(5.4)	(20.1)	(55.6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	11.7	11.7
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	9.0	9.0
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	78.9	35.7	—	114.6
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2018	$ 90.9	$ (101.0)	$ 164.5	154.4
Commodity Cash Flow Hedge Contracts				(24.8)
Fair Value Hedge Contracts				(17.4)
Collateral Deposits				(13.8)
Total MTM Derivative Contract Net Assets as of December 31, 2018				$ 98.4

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

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is mitigated in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 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 December 31, 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	$ 480.4	$ 2.2	$ 478.2	3	$ 260.1
Noninvestment Grade	1.5	1.5	—	—	—
No External Ratings:					
Internal Investment Grade	120.8	—	120.8	3	79.9
Internal Noninvestment Grade	51.2	10.5	40.7	2	28.7
Total as of December 31, 2018	$ 653.9	$ 14.2	$ 639.7		

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 December 31, 2018, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 1.1	$ 1.8	$ 0.3	$ 0.1	$ 0.2	$ 0.5	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 4.0	$ 16.5	$ 2.7	$ 0.4	$ 4.1	$ 6.5	$ 1.0	$ 0.3

Management back-tests VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the twelve months ended December 31, 2018, 2017 and 2016, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $25 million, $28 million and $37 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows of American Electric Power Company, Inc. and subsidiary companies (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of American Electric Power Company, Inc. and subsidiary companies for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and Subsidiary Companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2018.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2018. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions, except per-share and share amounts)

	Years Ended December 31, 2018	2017	2016
REVENUES			
Vertically Integrated Utilities	$ 9,556.7	$ 9,095.1	$ 9,012.4
Transmission and Distribution Utilities	4,552.3	4,328.9	4,328.3
Generation & Marketing	1,818.1	1,771.4	2,858.7
Other Revenues	268.6	229.5	180.7
TOTAL REVENUES	16,195.7	15,424.9	16,380.1
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	2,359.4	2,346.5	2,908.9
Purchased Electricity for Resale	3,427.1	2,965.3	2,821.4
Other Operation	2,979.2	2,525.2	2,996.1
Maintenance	1,247.4	1,145.6	1,241.7
Asset Impairments and Other Related Charges	70.6	87.1	2,267.8
Gain on Sale of Merchant Generation Assets	—	(226.4)	—
Depreciation and Amortization	2,286.6	1,997.2	1,962.3
Taxes Other Than Income Taxes	1,142.7	1,059.4	1,018.0
TOTAL EXPENSES	13,513.0	11,899.9	15,216.2
OPERATING INCOME	2,682.7	3,525.0	1,163.9
Other Income (Expense):			
Interest and Investment Income	11.6	16.0	16.3
Carrying Costs Income	6.6	18.6	16.2
Allowance for Equity Funds Used During Construction	132.5	93.7	113.2
Non-Service Cost Components of Net Periodic Benefit Cost	124.5	45.5	43.2
Gain on Sale of Equity Investment	—	12.4	—
Interest Expense	(984.4)	(895.0)	(877.2)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1,973.5	2,816.2	475.6
Income Tax Expense (Benefit)	115.3	969.7	(73.7)
Equity Earnings of Unconsolidated Subsidiaries	73.1	82.4	71.2
INCOME FROM CONTINUING OPERATIONS	1,931.3	1,928.9	620.5
LOSS FROM DISCONTINUED OPERATIONS, NET OF TAX	—	—	(2.5)
NET INCOME	1,931.3	1,928.9	618.0
Net Income Attributable to Noncontrolling Interests	7.5	16.3	7.1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,923.8	$ 1,912.6	$ 610.9
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	492,774,600	491,814,651	491,495,458
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 3.90	$ 3.89	$ 1.25
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.90	$ 3.89	$ 1.24
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	493,758,277	492,611,067	491,662,007
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 3.90	$ 3.88	$ 1.25
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.90	$ 3.88	$ 1.24

See Notes to Financial Statements of Registrants beginning on page 79.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
Net Income	$ 1,931.3	$ 1,928.9	$ 618.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $3.9, $(1.4) and $(8.8) in 2018, 2017 and 2016, Respectively	14.6	(2.6)	(16.4)
Securities Available for Sale, Net of Tax of $0, $1.9 and $0.7 in 2018, 2017 and 2016, Respectively	—	3.5	1.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(1.4), $0.6 and $0.3 in 2018, 2017 and 2016, Respectively	(5.3)	1.1	0.6
Pension and OPEB Funded Status, Net of Tax of $(8.8), $46.7 and $(7.9) in 2018, 2017 and 2016, Respectively	(33.0)	86.5	(14.7)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(23.7)	88.5	(29.2)
TOTAL COMPREHENSIVE INCOME	1,907.6	2,017.4	588.8
Total Comprehensive Income Attributable to Noncontrolling Interests	7.5	16.3	7.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,900.1	$ 2,001.1	$ 581.7

See Notes to Financial Statements of Registrants beginning on page 79.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2015	511.4	$ 3,324.0	$ 6,296.5	$ 8,398.3	$ (127.1)	$ 13.2	$ 17,904.9
Issuance of Common Stock	0.6	4.3	29.9				34.2
Common Stock Dividends				(1,116.8) (a)		(4.2)	(1,121.0)
Other Changes in Equity			6.2			7.0	13.2
Net Income				610.9		7.1	618.0
Other Comprehensive Loss					(29.2)		(29.2)
TOTAL EQUITY – DECEMBER 31, 2016	512.0	3,328.3	6,332.6	7,892.4	(156.3)	23.1	17,420.1
Issuance of Common Stock	0.2	1.1	11.1				12.2
Common Stock Dividends				(1,178.3) (a)		(13.6)	(1,191.9)
Other Changes in Equity			55.0			0.8	55.8
Net Income				1,912.6		16.3	1,928.9
Other Comprehensive Income					88.5		88.5
TOTAL EQUITY – DECEMBER 31, 2017	512.2	3,329.4	6,398.7	8,626.7	(67.8)	26.6	18,313.6
Issuance of Common Stock	1.3	8.0	65.6				73.6
Common Stock Dividends				(1,251.1) (a)		(4.4)	(1,255.5)
Other Changes in Equity			21.8			1.3	23.1
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				1,923.8		7.5	1,931.3
Other Comprehensive Loss					(23.7)		(23.7)
TOTAL EQUITY – DECEMBER 31, 2018	513.5	$ 3,337.4	$ 6,486.1	$ 9,325.3	$ (120.4)	$ 31.0	$ 19,059.4

(a) Cash dividends declared per AEP common share were $2.53, $2.39 and $2.27 for the years ended December 31, 2018, 2017 and 2016, respectively.

See Notes to Financial Statements of Registrants beginning on page 79.

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

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 234.1	$ 214.6
Restricted Cash (December 31, 2018 and 2017 Amounts Include $210 and $198, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding)	210.0	198.0
Other Temporary Investments (December 31, 2018 and 2017 Amounts Include $152.7 and $155.4, Respectively, Related to EIS and Transource Energy)	159.1	161.7
Accounts Receivable:		
Customers	699.0	643.9
Accrued Unbilled Revenues	209.3	230.2
Pledged Accounts Receivable – AEP Credit	999.8	954.2
Miscellaneous	55.2	101.2
Allowance for Uncollectible Accounts	(36.8)	(38.5)
Total Accounts Receivable	1,926.5	1,891.0
Fuel	341.5	387.7
Materials and Supplies	579.6	565.5
Risk Management Assets	162.8	126.2
Regulatory Asset for Under-Recovered Fuel Costs	150.1	292.5
Margin Deposits	141.4	105.5
Prepayments and Other Current Assets	208.8	310.4
TOTAL CURRENT ASSETS	4,113.9	4,253.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	21,699.9	20,760.5
Transmission	21,531.0	18,972.5
Distribution	21,195.4	19,868.5
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,265.0	3,706.3
Construction Work in Progress	4,393.9	4,120.7
Total Property, Plant and Equipment	73,085.2	67,428.5
Accumulated Depreciation and Amortization	17,986.1	17,167.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	55,099.1	50,261.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,310.4	3,587.6
Securitized Assets	920.6	1,211.2
Spent Nuclear Fuel and Decommissioning Trusts	2,474.9	2,527.6
Goodwill	52.5	52.5
Long-term Risk Management Assets	254.0	282.1
Deferred Charges and Other Noncurrent Assets	2,577.4	2,553.5
TOTAL OTHER NONCURRENT ASSETS	9,589.8	10,214.5
TOTAL ASSETS	$ 68,802.8	$ 64,729.1

See Notes to Financial Statements of Registrants beginning on page 79.

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

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable	$ 1,874.3	$ 2,065.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	718.0
Other Short-term Debt	1,160.0	920.6
Total Short-term Debt	1,910.0	1,638.6
Long-term Debt Due Within One Year (December 31, 2018 and 2017 Amounts Include $406.5 and $406.9, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	1,698.5	1,753.7
Risk Management Liabilities	55.0	61.6
Customer Deposits	412.2	357.0
Accrued Taxes	1,218.0	1,115.5
Accrued Interest	231.7	234.5
Regulatory Liability for Over-Recovered Fuel Costs	58.6	11.9
Other Current Liabilities	1,190.5	1,033.2
TOTAL CURRENT LIABILITIES	8,648.8	8,271.3
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2018 and 2017 Amounts Include $1,109.2 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)	21,648.2	19,419.6
Long-term Risk Management Liabilities	263.4	322.0
Deferred Income Taxes	7,086.5	6,813.9
Regulatory Liabilities and Deferred Investment Tax Credits	8,540.3	8,422.3
Asset Retirement Obligations	2,287.7	1,925.5
Employee Benefits and Pension Obligations	377.1	398.1
Deferred Credits and Other Noncurrent Liabilities	782.6	830.9
TOTAL NONCURRENT LIABILITIES	40,985.8	38,132.3
TOTAL LIABILITIES	49,634.6	46,403.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	69.4	—
Contingently Redeemable Performance Share Awards	39.4	11.9
TOTAL MEZZANINE EQUITY	108.8	11.9
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2018	2017
Shares Authorized	600,000,000	600,000,000
Shares Issued	513,450,036	512,210,644

	2018	2017
(20,204,160 and 20,205,046 Shares were Held in Treasury as of December 31, 2018 and 2017, Respectively)	3,337.4	3,329.4
Paid-in Capital	6,486.1	6,398.7
Retained Earnings	9,325.3	8,626.7
Accumulated Other Comprehensive Income (Loss)	(120.4)	(67.8)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,028.4	18,287.0
Noncontrolling Interests	31.0	26.6
TOTAL EQUITY	19,059.4	18,313.6
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$ 68,802.8	$ 64,729.1

See Notes to Financial Statements of Registrants beginning on page 79.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 1,931.3	$ 1,928.9	$ 618.0
Loss from Discontinued Operations, Net of Tax	—	—	(2.5)
Income from Continuing Operations	1,931.3	1,928.9	620.5
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:			
Depreciation and Amortization	2,286.6	1,997.2	1,962.3
Deferred Income Taxes	104.3	901.5	(50.0)
Asset Impairments and Other Related Charges	70.6	87.1	2,267.8
Allowance for Equity Funds Used During Construction	(132.5)	(93.7)	(113.2)
Mark-to-Market of Risk Management Contracts	(66.4)	(23.3)	150.8
Amortization of Nuclear Fuel	113.8	129.1	128.6
Pension and Postemployment Benefit Reserves	(42.8)	27.8	21.6
Pension Contributions to Qualified Plan Trust	—	(93.3)	(84.8)
Property Taxes	(59.1)	(29.5)	(19.0)
Deferred Fuel Over/Under-Recovery, Net	189.7	84.4	(65.5)
Gain on Sale of Merchant Generation Assets	—	(226.4)	—
Recovery of Ohio Capacity Costs, Net	67.7	83.2	88.1
Provision for Refund – Global Settlement, Net	(5.5)	(98.2)	120.3
Disposition of Tanners Creek Plant Site	—	—	(93.5)
Change in Other Noncurrent Assets	119.8	(423.9)	(454.6)
Change in Other Noncurrent Liabilities	129.0	181.7	15.4
Changes in Certain Components of Continuing Working Capital:			
Accounts Receivable, Net	145.9	28.5	(226.6)
Fuel, Materials and Supplies	20.7	17.9	60.2
Accounts Payable	36.6	(58.0)	164.9
Accrued Taxes, Net	153.2	91.9	42.8
Other Current Assets	10.5	(60.7)	14.2
Other Current Liabilities	149.8	(181.8)	(28.5)
Net Cash Flows from Continuing Operating Activities	5,223.2	4,270.4	4,521.8
INVESTING ACTIVITIES			
Construction Expenditures	(6,310.9)	(5,691.3)	(4,781.1)
Purchases of Investment Securities	(2,067.8)	(2,314.7)	(3,002.3)
Sales of Investment Securities	2,010.0	2,256.3	2,957.7
Acquisitions of Nuclear Fuel	(46.1)	(108.0)	(128.5)
Acquisitions of Assets/Businesses	(14.6)	(6.8)	(107.9)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6	—
Other Investing Activities	75.8	48.5	15.5
Net Cash Flows Used for Continuing Investing Activities	(6,353.6)	(3,656.4)	(5,046.6)
FINANCING ACTIVITIES			
Issuance of Common Stock	73.6	12.2	34.2
Issuance of Long-term Debt	4,945.7	3,854.1	2,594.9
Commercial Paper and Credit Facility Borrowings	205.6	—	—
Change in Short-term Debt, Net	271.4	(74.4)	913.0
Retirement of Long-term Debt	(2,782.0)	(3,087.9)	(1,794.9)
Commercial Paper and Credit Facility Repayments	(205.6)	—	—
Make Whole Premium on Extinguishment of Long-term Debt	(13.5)	(46.1)	—
Principal Payments for Capital Lease Obligations	(65.1)	(67.3)	(106.6)
Dividends Paid on Common Stock	(1,255.5)	(1,191.9)	(1,121.0)
Other Financing Activities	(12.7)	(3.6)	(15.7)
Net Cash Flows from (Used for) Continuing Financing Activities	1,161.9	(604.9)	503.9
Net Cash Flows Used for Discontinued Operating Activities	—	—	(2.5)
Net Cash Flows from Discontinued Investing Activities	—	—	—
Net Cash Flows from Discontinued Financing Activities	—	—	—
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	31.5	9.1	(23.4)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	412.6	403.5	426.9
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 444.1	$ 412.6	$ 403.5

See Notes to Financial Statements of Registrants beginning on page 79.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

The notes to 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. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

ORGANIZATION

The Registrants engage in the generation, transmission and distribution of electric power. The Registrant Subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP provides competitive electric and gas supply for residential, commercial and industrial customers in deregulated electricity markets and also provides energy management solutions throughout the United States, including energy efficiency services through its independent retail electric supplier.

The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, AEP operates competitive wind and solar farms. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrants' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that the Registrants have "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers pay for certain deferred generation-related costs through non-bypassable charges. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has no active REPs in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT.

The FERC also regulates the Registrants' wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Ohio for OPCo, in Virginia for APCo and in Michigan for I&M. AEP Texas' retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for AEPTCo's seven wholly-owned transmission subsidiaries within the AEP Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the SIA, Operating Agreement, Transmission Agreement and Transmission Coordination Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA and the Bridge Agreement, see Note 16 - Related Party Transactions for additional information.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for AEP Texas include the Registrant Subsidiary, its wholly-owned subsidiaries and Transition Funding (consolidated VIEs). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a consolidated VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (consolidated VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and Ohio Phase-in-Recovery Funding (a consolidated VIE). The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a consolidated VIE). Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. AEP, AEP Texas, I&M, PSO and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Note 18 - Property, Plant and Equipment.

Accounting for the Effects of Cost-Based Regulation

The Registrants' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

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:

	December 31, 2018			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 234.1	$ 3.1	$ 4.2	$ 4.9
Restricted Cash	210.0	156.7	25.6	27.6
Total Cash, Cash Equivalents and Restricted Cash	$ 444.1	$ 159.8	$ 29.8	$ 32.5

	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

Other Temporary Investments (Applies to AEP)

Other Temporary Investments primarily include marketable securities and investments by its protected cell of EIS. These securities have readily determinable fair values and are carried at fair value with changes in fair value recognized in net income. The cost of securities sold is based on the specific identification or weighted-average cost method. See "Fair Value Measurements of Other Temporary Investments" section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR and AEP's non-regulated ownership share of Oklaunion Plant, which is carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See "Sale of Receivables – AEP Credit" section of Note 14 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers (Applies to Registrant Subsidiaries)

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant transactions with REPs which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Centrica, Just Energy, TXU Energy and Reliant Energy	**2018 (b)**	**2017 (a)(b)**	**2016 (a)**
Percentage of Total Revenues	45%	35%	46%
Percentage of Accounts Receivable – Customers	35%	31%	42%

(a) TXU Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.
(b) Just Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	**2018**	**2017**	**2016**
Percentage of Total Revenues	77%	80%	77%
Percentage of Total Accounts Receivable	84%	85% (a)	86%

(a) Reflects the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Emission Allowances and Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record emission allowances and renewable energy credits (RECs) at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For AEP's competitive generation business, management records allowances and RECs at the lower of cost or market. The Registrants follow the inventory model for these allowances and RECs. Allowances and RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. Allowances and RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of allowances and RECs are reported in the Operating Activities section of the statements of cash flows. Allowances are consumed in the production of energy, and RECs are consumed to meet applicable state renewable portfolio standards and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of emission allowances is included in Vertically Integrated Utilities Revenues on AEP's statements of income and in Electric Generation, Transmission and Distribution Revenues on the Registrant Subsidiaries' statements of income because of its integral nature to the production process of energy and the Registrants' revenue optimization strategy for their operations. The net margin on sales of emission allowances and RECs affects the determination of deferred fuel or deferred emission allowance and REC costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Nonregulated operations generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at original cost (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. The Registrants record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

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 benefits and 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 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. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs (Applies to all Registrants except AEP Texas and AEPTCo)

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a commission-approved plan to delay refunds or recoveries beyond a one year period. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable.

Changes in fuel costs, including purchased power in Kentucky for KPCo, Indiana and Michigan for I&M, in Ohio (through the ESP related to SSO load served through auctions) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO, in Virginia and West Virginia for APCo and in West Virginia for WPCo are reflected in rates in a timely manner generally through the FAC. In Ohio, changes in fuel costs incurred from 2009 through 2011, that continued to be recovered in rider rates were terminated in January 2019. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo and WPCo, all of the non-merchant margins from off-system sales are given to customers through the FAC. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are tested for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

The Registrants recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the applicable state commission's regulatory treatment, PSO and SWEPCo do not include the fuel portion in unbilled revenue, but rather recognize such revenues when billed to customers.

Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations", and are recognized by the Registrants in the second quarter following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 20 - Revenue from Contracts with Customers for additional information related to retail and wholesale revenues.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM or SPP. The Registrants also purchase power from PJM and SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrants record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

The Registrants engage in power, capacity and, to a lesser extent, natural gas marketing as major power producers and participants in electricity and natural gas markets. The Registrants also engage in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrants recognize revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event the Registrants designate a cash flow hedge, cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrants subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Levelization of Nuclear Refueling Outage Costs (Applies to AEP and I&M)

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

The Registrants expense maintenance costs as incurred. If it becomes probable that the Registrants will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulated jurisdictions, the Registrants defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. The Registrants revalued deferred tax assets and liabilities at the new federal corporate income tax rate of 21% in December 2017. See Note 12 - Income Taxes for additional information related to Tax Reform.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

AEP and subsidiaries apply the deferral methodology for the recognition of ITC. Deferred ITC is amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

The Registrants account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrants classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes (Applies to all Registrants except AEPTCo)

As agents for some state and local governments, the Registrants collect from customers certain excise taxes levied by those state or local governments on customers. The Registrants do not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Goodwill (Applies to AEP)

When AEP acquires businesses, management records the fair value of all assets and liabilities. To the extent that consideration exceeds the fair value of identified assets, goodwill is recorded. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at their estimated fair value. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods.

Pension and OPEB Plans (Applies to all Registrants except AEPTCo)

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. The Registrant Subsidiaries account for their participation in the AEP sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and SNF disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	49%
Fixed Income	49%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2018 and 2017, the fair value of securities on loan as part of the program was $241 million and $492 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2018 and 2017.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds (Applies to AEP and I&M)

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

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

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. With the adoption of ASU 2016-01, effective January 2018, available for sale classification only applies to investment in debt securities. Additionally, the adoption of ASU 2016-01 required changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M's trust fund 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. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss) (Applies to all Registrants except AEPTCo)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2018, AEP had performance units and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, performance units awarded prior to 2017 are settled in cash and restricted stock units are settled in AEP common shares, except for restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vest to executive officers, which are settled in cash. All performance units and restricted stock units awarded after January 1, 2017 will be settled in AEP common shares. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance units granted to employees under the 2015 LTIP. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. All AEP career shares are paid out in AEP common stock after the executive's service with AEP ends.

Performance units awarded after January 1, 2017 are classified as temporary equity in the Mezzanine Equity section of the balance sheets. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity.

AEP compensates their non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2018, 2017 and 2016 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2018, 2017 and 2016, compensation cost is included in Net Income for the performance units, career shares, restricted stock units and the non-employee director's stock units. Compensation cost may also be capitalized. See Note 15 - Stock-based Compensation for additional information.

Equity Investment in Unconsolidated Affiliates (Applies to AEP and SWEPCo)

AEP and SWEPCo include equity in earnings from equity method investments in Equity Earnings (Loss) of Unconsolidated Subsidiaries on the statements of income. AEP and SWEPCo regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

AEP has two significant equity method investments, ETT and DHLC. ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. Berkshire Hathaway Energy, a nonaffiliated entity, holds a 50% membership interest in ETT, AEP Transmission Holdco holds a 49.5% membership interest in ETT and AEP Transmission Partner holds the remaining 0.5% membership interest in ETT. As a result, AEP, through its wholly-owned subsidiaries, holds a 50% membership interest in ETT. As of December 31, 2018 and 2017, AEP's investment in ETT was $666 million and $664 million, respectively, which is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP's equity earnings associated with ETT were $62 million and $82 million for the years ended December 31, 2018 and 2017. See "Non-Consolidated Significant Variable Interest" section of Note 17 for more information about DHLC.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Years Ended December 31,					
	2018		**2017**		**2016**	
	(in millions, except per share data)					
		$/share		**$/share**		**$/share**
Income from Continuing Operations	$1,931.3		$1,928.9		$ 620.5	
Less: Net Income Attributable to Noncontrolling Interests	7.5		16.3		7.1	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$1,923.8		$1,912.6		$ 613.4	
Weighted Average Number of Basic Shares Outstanding	492.8	$ 3.90	491.8	$ 3.89	491.5	$ 1.25
Weighted Average Dilutive Effect of Stock-Based Awards	1.0	—	0.8	(0.01)	0.2	—
Weighted Average Number of Diluted Shares Outstanding	493.8	$ 3.90	492.6	$ 3.88	491.7	$ 1.25

There were no antidilutive shares outstanding as of December 31, 2018, 2017 and 2016.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2018, 2017 and 2016:

2018

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,965.0	$ 262.2	$ 133.9	$ 428.1	$ 278.9	$ 232.6	$ 155.5	$ 237.0
Amortization of Certain Securitized Assets	287.9	240.0	—	—	—	47.9	—	—
Amortization of Regulatory Assets and Liabilities	33.7	(2.6)	—	0.3	14.2	(20.8)	8.5	2.5
Total Depreciation and Amortization	$ 2,286.6	$ 499.6	$ 133.9	$ 428.4	$ 293.1	$ 259.7	$ 164.0	$ 239.5

2017

Depreciation and Amortization	AEP	AEP Texas	AEPTCo (a)	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,709.1	$ 221.1	$ 95.7	$ 407.6	$ 203.1	$ 200.9	$ 131.4	$ 217.2
Amortization of Certain Securitized Assets	275.9	231.4	—	—	—	44.4	—	—
Amortization of Regulatory Assets and Liabilities	12.2	(2.4)	—	0.3	7.8	(19.4)	(1.0)	0.2
Total Depreciation and Amortization	$ 1,997.2	$ 450.1	$ 95.7	$ 407.9	$ 210.9	$ 225.9	$ 130.4	$ 217.4

2016

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,688.5	$ 204.0	$ 65.9	$ 387.6	$ 183.9	$ 202.3	$ 122.6	$ 196.6
Amortization of Certain Securitized Assets	254.6	210.3	—	—	—	44.3	—	—
Amortization of Regulatory Assets and Liabilities	19.2	(0.4)	—	0.9	7.8	(8.0)	7.6	(0.1)
Total Depreciation and Amortization	$ 1,962.3	$ 413.9	$ 65.9	$ 388.5	$ 191.7	$ 238.6	$ 130.2	$ 196.5

(a) Reflects the revisions made to AEPTCo's previously issued financial statements. For additional details on the revisions to AEPTCo's financial statements, see "Revisions to Previously Issued Financial Statements" below.

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	2018	2017	2016
	Years Ended December 31, (in millions)		
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 939.3	$ 858.3	$ 848.5
Income Taxes	(24.7)	(1.1)	29.5
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	55.6	60.7	86.1
Construction Expenditures Included in Current Liabilities as of December 31,	1,120.4	1,330.8	858.0
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	71.8	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	4.0	—	2.1
Noncash Contribution of Assets by Noncontrolling Interest	84.0	—	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.2	2.6	0.7

Revisions to Previously Issued Financial Statements (Applies to AEPTCo)

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

Management assessed the materiality of the misstatements on all previously issued AEPTCo financial statements in accordance with SEC Staff Accounting Bulletin (SAB) No. 99, Materiality, codified in ASC 250, Presentation of Financial Statements and concluded these misstatements were not material, individually or in the aggregate, to any prior annual or interim period. In accordance with ASC 250 (SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements), management revised the prior period AEPTCo financial statements included in this report to reflect the impact of correcting the immaterial misstatements described above. In addition, management will revise the March 31, 2018 and June 30, 2018 periods presented in AEPTCo's previously issued financial statements in future SEC Form 10-Q filings to reflect the impact of the misstatements. The $(20) million adjustment to pretax income for the year ended December 31, 2017 includes adjustments of $(12) million relating to 2016 and earlier periods. The effect of recording this adjustment of $(12) million in 2017 is not material to AEPTCo's financial statements for 2017 or any earlier period.

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

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

Statement of Income

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's statement of income for the twelve months ended December 31, 2017:

	Twelve Months Ended December 31, 2017		
	As Reported	Adjustments	As Adjusted
		(in millions)	
TOTAL REVENUES	$ 723.2	$ (16.3)	$ 706.9
EXPENSES			
Depreciation and Amortization	97.1	(1.4)	95.7
TOTAL EXPENSES	275.4	(1.4)	274.0
OPERATING INCOME	447.8	(14.9)	432.9
Other Income (Expense):			
Allowance for Equity Funds Used During Construction	52.3	(3.3)	49.0
Interest Expense	(68.0)	(2.2)	(70.2)
INCOME BEFORE INCOME TAX EXPENSE	433.3	(20.4)	412.9
Income Tax Expense	147.2	(5.0)	142.2
NET INCOME	$ 286.1	$ (15.4)	$ 270.7

Balance Sheet

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

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

Statement of Cash Flows

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's statement of cash flows for the twelve months ended December 31, 2017:

	Twelve Months Ended December 31, 2017		
	As Reported	Adjustments	As Adjusted
		(in millions)	
OPERATING ACTIVITIES			
Net Income	$ 286.1	$ (15.4)	$ 270.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	97.1	(1.4)	95.7
Deferred Income Taxes	272.8	(1.3)	271.5
Allowance for Equity Funds Used During Construction	(52.3)	3.3	(49.0)
Property Taxes	(15.6)	(7.2)	(22.8)
Change in Other Noncurrent Assets	9.8	1.2	11.0
Change in Other Noncurrent Liabilities	27.3	0.2	27.5
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(34.5)	4.1	(30.4)
Accounts Payable	9.8	13.2	23.0
Accrued Taxes, Net	13.0	3.3	16.3
Net Cash Flows from Operating Activities	604.8	—	604.8
INVESTING ACTIVITIES			
Net Cash Flows Used for Investing Activities	(1,595.6)	—	(1,595.6)
FINANCING ACTIVITIES			
Net Cash Flows from Financing Activities	990.8	—	990.8
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	$ 61.2	$ 1.2	$ 62.4
Construction Expenditures Included in Current Liabilities as of December 31,	473.7	11.3	485.0

Statement of Changes in Member's Equity

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

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 with a customer, 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 flows arising from contracts with customers.

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach for all contracts within the scope of the new standard. 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 20 - 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 to the results of operations and financial position of AEP, and no impact to the results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants.

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

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

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheet. Management elected 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.
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.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheet in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheet. The impact to the balance sheet has been estimated for the first quarter of 2019 as shown in the table below.

Company	Estimated Obligation
	(in millions)
AEP	$ 1,070.4
AEP Texas	80.2
AEPTCo	5.4
APCo	80.4
I&M	351.1
OPCo	76.8
PSO	32.2
SWEPCo	35.8

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 and related implementation guidance 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 is 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 of the new standard 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 to 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 for assessments 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 to the 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. The adoption of the new standard did not give rise to any material changes to the Registrants' previously established accounting policies for derivatives and hedging.

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

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

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

ASU 2018-14 "Disclosure Framework: Changes to the Disclosure Requirements for Defined Benefit Plans" (ASU 2018-14)

In August 2018, the FASB issued ASU 2018-14 modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendments in this Update to Subtopic 715-20 remove disclosures that no longer are considered cost beneficial, clarify the specific requirements of disclosures and add disclosure requirements identified as relevant.

Management early adopted ASU 2018-14 for the 2018 Annual Report and applied the new standard retrospectively for all periods presented. As a result of adoption, the Registrants' disclosures were updated as follows:

- Amended the disclosure to remove the amounts in AOCI expected to be recognized as components of net periodic benefit cost over the next fiscal year.
- Amended the disclosure to remove the effects of a one-percentage-point change in assumed health care cost trend rates on the (a) aggregate of the service and interest cost components of net periodic benefit costs and (b) benefit obligation for postretirement health care benefits.
- Amended the disclosure to include the weighted-average interest crediting rates for cash balance plans and other plans with promised interest crediting rates.
- Amended the disclosure to include an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period.

See Note 8 - Benefit Plans for updates to the disclosures required by the new standard.

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

In August 2018, the FASB issued ASU 2018-15 aligning the requirements for capitalizing implementation costs incurred in a cloud computing arrangement (hosting arrangement) that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The new standard requires an entity (customer) in a hosting arrangement that is a service contract to follow the accounting guidance for "Internal-Use Software" to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. To eliminate diversity in practice, the new standard changes the presentation of implementation costs for cloud service arrangements that are service contracts without the purchase of a license. Implementation costs for cloud service contracts will be presented on the balance sheets in the same manner as a prepayment. The Registrants currently present implementation costs in property, plant and equipment on the balance sheets. Under the new standard, amortization of capitalized implementation costs of a hosting arrangement will be recorded in Operation and Maintenance expense over the term of the cloud service arrangement, rather than Depreciation and Amortization expense on the statements of income. Payments for capitalized implementation costs in the statement of cash flows will be classified in the same manner as payments made for fees associated with the hosting element.

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

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2018, 2017 and 2016. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)
Change in Fair Value Recognized in AOCI	37.3	2.3	—	—	(33.0)	6.6
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (a)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (a)	(32.6)	—	—	—	—	(32.6)
Interest Expense (a)	—	1.1	—	—	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains) Losses	—	—	—	12.8	—	12.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(32.7)	1.1	—	(6.7)	—	(38.3)
Income Tax (Expense) Benefit	(6.9)	0.3	—	(1.4)	—	(8.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(25.8)	0.8	—	(5.3)	—	(30.3)
Net Current Period Other Comprehensive Income (Loss)	11.5	3.1	—	(5.3)	(33.0)	(23.7)
ASU 2018-02 Adoption (b)	(6.1)	(2.7)	—	—	(8.2)	(17.0)
ASU 2016-01 Adoption (b)	—	—	(11.9)	—	—	(11.9)
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ —	$ 136.3	$ (221.1)	$ (120.4)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)
Change in Fair Value Recognized in AOCI	(20.4)	1.6	3.5	—	86.5	71.2
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (a)	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale (a)	28.8	—	—	—	—	28.8
Interest Expense (a)	—	1.5	—	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	—	(19.6)	—	(19.6)
Amortization of Actuarial (Gains) Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	23.2	1.5	—	1.7	—	26.4
Income Tax (Expense) Benefit	8.1	0.4	—	0.6	—	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	15.1	1.1	—	1.1	—	17.3
Net Current Period Other Comprehensive Income (Loss)	(5.3)	2.7	3.5	1.1	86.5	88.5
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2015	$ (5.2)	$ (17.2)	$ 7.1	$ 139.9	$ (251.7)	$ (127.1)
Change in Fair Value Recognized in AOCI	(14.6)	—	1.3	—	(14.7)	(28.0)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (a)	(21.4)	—	—	—	—	(21.4)
Purchased Electricity for Resale (a)	16.4	—	—	—	—	16.4
Interest Expense (a)	—	2.4	—	—	—	2.4
Amortization of Prior Service Cost (Credit)	—	—	—	(19.4)	—	(19.4)
Amortization of Actuarial (Gains) Losses	—	—	—	20.3	—	20.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(5.0)	2.4	—	0.9	—	(1.7)
Income Tax (Expense) Benefit	(1.7)	0.9	—	0.3	—	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(3.3)	1.5	—	0.6	—	(1.2)
Net Current Period Other Comprehensive Income (Loss)	(17.9)	1.5	1.3	0.6	(14.7)	(29.2)
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.3	—	1.6
Income Tax (Expense) Benefit	0.3	0.1	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	(1.0)	0.2
ASU 2018-02 Adoption (b)	(0.9)	—	(1.8)	(2.7)
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.4	—	1.7
Income Tax (Expense) Benefit	0.4	0.1	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.9	0.3	—	1.2
Net Current Period Other Comprehensive Income (Loss)	0.9	0.3	1.1	2.3
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (6.5)	$ 3.9	$ (14.6)	$ (17.2)
Change in Fair Value Recognized in AOCI	(0.1)	—	0.9	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	1.8	—	—	1.8
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.8	0.4	—	2.2
Income Tax (Expense) Benefit	0.6	0.1	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.2	0.3	—	1.5
Net Current Period Other Comprehensive Income (Loss)	1.1	0.3	0.9	2.3
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ 14.8	$ (15.7)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(2.6)	(3.3)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (a)	0.9	—	—	—	0.9
Interest Expense (a)	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	—	1.3	—	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(1.1)	(3.9)	—	(4.1)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.8)	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.9)	(3.1)	—	(3.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.9)	(3.1)	(2.6)	(6.6)
ASU 2018-02 Adoption (b)	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	$ —	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	11.6	11.6
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	3.4	—	3.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(1.8)	—	(2.9)
Income Tax (Expense) Benefit	(0.4)	(0.6)	—	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.2)	—	(1.9)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.2)	11.6	9.7
Balance in AOCI as of December 31, 2017	$ 2.2	$ 14.8	$ (15.7)	$ 1.3

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ 3.6	$ 17.4	$ (23.8)	$ (2.8)
Change in Fair Value Recognized in AOCI	—	—	(3.5)	(3.5)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains) Losses	—	3.0	—	3.0
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(2.1)	—	(3.2)
Income Tax (Expense) Benefit	(0.4)	(0.7)	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.4)	—	(2.1)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.4)	(3.5)	(5.6)
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption (b)	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)
Change in Fair Value Recognized in AOCI	—	—	(0.8)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	(0.8)	0.5
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(1.3)
ASU 2018-02 Adoption (b)	0.4
Balance in AOCI as of December 31, 2018	$ 1.0

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.1)
Net Current Period Other Comprehensive Income (Loss)	(1.1)
Balance in AOCI as of December 31, 2017	$ 1.9

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2015	$ 4.3
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.9)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.9)
Income Tax (Expense) Benefit	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(1.3)
Balance in AOCI as of December 31, 2016	$ 3.0

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
ASU 2018-02 Adoption (b)	0.5
Balance in AOCI as of December 31, 2018	$ 2.1

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2017	$ 2.6

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2015	$ 4.2
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.2)
Income Tax (Expense) Benefit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2016	$ 3.4

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)
Change in Fair Value Recognized in AOCI	2.3	—	(3.1)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.1	—	—	2.1
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.2	—	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.1	(1.8)	—	0.3
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(1.4)	—	0.3
Net Current Period Other Comprehensive Income (Loss)	4.0	(1.4)	(3.1)	(0.5)
ASU 2018-02 Adoption (b)	(1.3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	4.7	4.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.2	—	—	2.2
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.2	(1.1)	—	1.1
Income Tax (Expense) Benefit	0.8	(0.4)	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.4	(0.7)	—	0.7
Net Current Period Other Comprehensive Income (Loss)	1.4	(0.7)	4.7	5.4
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (9.1)	$ 2.6	$ (2.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.7	—	—	2.7
Amortization of Prior Service Cost (Credit)	—	(1.8)	—	(1.8)
Amortization of Actuarial (Gains) Losses	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.7	(1.1)	—	1.6
Income Tax (Expense) Benefit	1.0	(0.4)	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(0.7)	—	1.0
Net Current Period Other Comprehensive Income (Loss)	1.7	(0.7)	(1.0)	—
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)

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

4. RATE MATTERS

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

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

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 12 - Income Taxes.

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

AEP Texas Interim Transmission and Distribution Rates

As of December 31, 2018, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2018, subject to review, are estimated to be $1 billion. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

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

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

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

Hurricane Harvey and Texas Storm Cost Securitization

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 December 31, 2018, the total balance of AEP Texas' regulatory asset for deferred storm costs is approximately $152 million, inclusive of approximately $129 million of incremental storm expenses related to Hurricane Harvey. See the table below for additional information on the Hurricane Harvey storm restoration costs:

	December 31, 2018			
Total Hurricane Harvey Storm Costs	**Capital**	**O&M**	**Regulatory Asset**	**Total**
	(in millions)			
Restoration Costs Incurred	$ 219.1	$ 136.9	$ —	$ 356.0
Incremental Operation and Maintenance Expenses (O&M)	—	(129.8)	129.8	—
Insurance Proceeds	(12.7)	—	(1.2)	(13.9)
Total Hurricane Harvey Storm Costs, Net	$ 206.4	$ 7.1	$ 128.6	$ 342.1

The securitization of storm cost recovery in Texas requires two filings with the PUCT. In August 2018, AEP Texas filed a Determination of System Restoration Costs (DSRC) with the PUCT for total estimated storm costs in the amount of $425 million, which includes estimated carrying costs. The total estimated storm costs net of insurance proceeds, tax credits received for the Disaster Tax Relief and Airport and Airway Extension Act of 2017, and Excess ADIT that is not subject to rate normalization requirements utilized to reduce the non-capital Hurricane Harvey costs is $370 million.

In November 2018, AEP Texas, the PUCT staff and intervenors filed a stipulation and settlement agreement with the PUCT that included all aspects of the DSRC filing with the following exceptions: (a) a $5 million permanent storm restoration reduction, (b) a $4 million disallowance of charges not directly related to storm restoration that will be included in a future regulatory proceeding and (c) a $5 million disallowance due to additional insurance proceeds received. See the table below for a reconciliation of the filed Determination of System Restoration Costs and settlement and stipulation agreement:

Total Estimated Storm Costs Requested in the DSRC	**December 31, 2018**
	(in millions)
Total Estimated Hurricane Harvey Storm Costs	$ 356.0
Estimated Hurricane Harvey Carrying Costs	31.5
Estimated Litigation Costs	0.6
Non-Hurricane Harvey Storm Restoration Costs	36.5
Total Estimated Storm Costs requested in the DSRC	424.6
less:	
Tax Credit	(0.8)
Insurance Proceeds	(8.7)
Excess ADIT (a)	(45.5)
Total Estimated Storm Costs requested in the DSRC, after adjustments	369.6
less:	
Settlement Agreement Adjustments	(10.6)
Incremental Insurance Proceeds Received	(5.1)
Total Estimated Storm Costs per Settlement Agreement	$ 353.9

(a) Amount represents Non-Hurricane Harvey Excess ADIT that is not subject to rate normalization requirements.

AEP Texas will seek to securitize estimated distribution related assets of $247 million in the first half of 2019 while the remaining $107 million of estimated transmission related assets is expected to be recovered through interim transmission filings or an upcoming base rate case. If these costs are not recovered, it could have an adverse effect on future net income, cash flows and financial condition.

<u>APCo and WPCo Rate Matters</u> (Applies to AEP and APCo)

Virginia Legislation Affecting Earnings Reviews

In 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo's existing generation and distribution base rates were frozen until after the Virginia SCC ruled on APCo's next biennial review. These amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

In March 2018, new Virginia legislation impacting investor-owned utilities was enacted, effective July 1, 2018, that: (a) on a one-time basis, required APCo to exclude $10 million of incurred fuel expenses from the July 2018 over/under recovery calculation, (b) reduced APCo's base rates by $50 million annually effective July 30, 2018, on an interim basis and subject to true-up, to reflect the reduction in the federal income tax rate due to Tax Reform, (c) will require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years ("triennial review"), (d) will require an adjustment in APCo's base rates on April 1, 2019 to reflect actual annual reductions in corporate income taxes due to Tax Reform, (e) will require APCo to seek approval from the Virginia

SCC for energy efficiency programs with projected costs in the aggregate of at least $140 million over the 10-year period ending July 1, 2028 and (f) will require APCo to construct and/or acquire solar generation facilities in Virginia, subject to approval of 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 earnings exceeding 70 basis points over the Virginia SCC authorized return on common equity would be refunded, or may be offset by capital expenditures in Virginia SCC approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. In November 2018, the Virginia SCC approved a return on common equity of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period and rate adjustment clauses from November 2018 through November 2020. Management has reviewed APCo's actual and forecasted earnings for the triennial period and concluded that it is not probable but is reasonably possible that APCo will over-earn in Virginia during the 2017-2019 triennial period. Due to various uncertainties, including weather, storm restoration, weather-normalized demand and potential customer shopping during 2019, management cannot estimate a range of potential APCo Virginia over-earnings during the 2017-2019 triennial period. The Virginia triennial review of APCo earnings could materially reduce future net income and cash flows and impact financial condition.

Virginia Staff Depreciation Study Request

In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense ($6 million related to transmission) with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of the Virginia SCC's upcoming Triennial Review of APCo, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review. If the Virginia SCC were to issue an order approving the Virginia staff's recommended retroactive change in APCo's Virginia depreciation rates, it would reduce future net income and cash flows and impact financial condition.

Virginia Tax Reform

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

In October 2018, APCo also submitted a filing with the Virginia SCC to resolve outstanding issues related to Tax Reform. The filing incorporated the $50 million being refunded to customers as disclosed in "Virginia Legislation Affecting Earnings Reviews" above and, if approved, will reduce APCo's base rates by an additional $7 million annually. The combined reduction in APCo's base rates due to Tax Reform will refund: (a) $39 million annually of excess federal income taxes collected since January 1, 2018 until new base rates are implemented, (b) $7 million annually of Excess ADIT associated with certain depreciable property using ARAM and (c) $11 million annually of Excess ADIT that is not subject to rate normalization requirements over 10 years.

In November 2018, the Virginia SCC staff filed testimony recommending a total annual reduction in APCo's base rates of $69 million. The proposed reduction consisted of: (a) $41 million annually of excess federal income taxes collected since January 1, 2018 until new base rates are implemented, (b) $9 million annually of Excess ADIT associated with certain depreciable property using ARAM and (c) $19 million annually of Excess ADIT that is not subject to rate normalization requirements over 5 years. The Virginia SCC staff also recommended that APCo provide a one-time credit of $23 million for estimated excess taxes collected from customers during the 15-month period ending March 31, 2019. Intervenors filed testimony recommending that the $23 million for estimated excess taxes collected from customers during the 15-month period ending March 31, 2019 be refunded over 1 year and Excess ADIT that is not subject to rate normalization requirements be refunded over 3 years.

In December 2018, APCo filed rebuttal testimony with the Virginia SCC generally agreeing with the Virginia SCC staff testimony. A hearing at the Virginia SCC was held in January 2019 where both APCo and the Virginia SCC staff lowered their reduction for excess federal income taxes collected since January 1, 2018 by $1 million. APCo anticipates a final order from the Virginia SCC by the end of the first quarter of 2019 and expects to implement additional customer rate credits in a tax-related rider starting in April 2019. The Virginia SCC's review of APCo's Tax Reform filing could reduce future net income and cash flows and impact financial condition.

2018 West Virginia Base Rate Case

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

In November 2018 APCo, WPCo, WVPSC staff and certain intervenors filed a Stipulation and Settlement agreement with the WVPSC. The agreement included a proposed annual base rate increase of $44 million ($36 million related to APCo) based upon a 9.75% return on common equity effective March 2019. The agreement provided for an annual increase of $18 million ($14 million related to APCo) due to increased annual depreciation expense. Depreciation rates were decreased from the original request primarily due to continuing with a 2040 retirement date for Clinch River Plant rather than APCo's proposed retirement date of 2025. The agreement also included: (a) a proposal to refund, through a rider, $24 million ($19 million related to APCo) of Excess ADIT that is not subject to rate normalization requirements over two years starting March 2019, (b) a proposal to utilize $14 million ($12 million related to APCo) of Excess ADIT that is not subject to rate normalization requirements to offset regulatory asset balances relating to ENEC, (c) an agreement to work with the WVPSC to establish economic incentive programs and (d) an agreement, barring any unforeseen events, to not initiate another base rate proceeding prior to April 1, 2020. An order from the WVPSC is expected in the first quarter 2019. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

West Virginia Tax Reform

In August 2018, the WVPSC approved a settlement agreement between APCo, WPCo and various intervenors that addresses the reduction in the federal income tax rate due to Tax Reform and provides refunds to customers, through a rider, effective September 1, 2018 of approximately $63 million ($51 million related to APCo) through June 2020. In addition, per the agreement, APCo and WPCo utilized $139 million ($125 million related to APCo) of current tax savings and Excess ADIT that is not subject to rate normalization requirements to offset regulatory asset balances related to carbon capture, storm damage, ENEC and vegetation management. The WVPSC order indicated that the remaining balance of Excess ADIT that is not subject to rate normalization requirements would be addressed at a later date.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. Through December 31, 2018, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $884 million. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

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

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

In December 2018, the PUCT approved ETT's request to refund $11 million of excess federal income taxes collected in 2018 prior to the reduction in transmission rates that were implemented on June 21, 2018. The refunds were completed in December 2018.

<u>I&M Rate Matters</u> (Applies to AEP and I&M)

2017 Indiana Base Rate Case

In 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. In February 2018, I&M filed a Stipulation and Settlement Agreement for a $97 million annual increase, based on a 9.95% return on equity, 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. In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement.

2017 Michigan Base Rate Case

In 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. In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenor's proposal for up to 10% of I&M's Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day, as well as the MPSC staff's recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a return on common equity of 9.8%. 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.

If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million. In October 2018, I&M filed a request with the MPSC seeking authority to defer costs related to customers choosing an alternate supplier starting in February 2019. In December 2018, the MPSC rejected I&M's request.

Michigan Tax Reform

In August 2018, the MPSC approved I&M's application to refund, through a rider, approximately $9 million annually for the impact of Tax Reform on I&M's Michigan jurisdictional earnings effective September 1, 2018. In October 2018, I&M also made two filings with the MPSC recommending to: (a) refund $3 million over eight months for the impact of Tax Reform on Michigan jurisdictional earnings for the period April 26, 2018 through August 31, 2018, (b) refund approximately $68 million of Excess ADIT associated with certain depreciable property using ARAM and (c) refund approximately $37 million of Excess ADIT that is not subject to rate normalization requirements over 10 years. In January 2019, I&M received an order from the MPSC requiring I&M to refund $5 million over six months, effective February 2019, for the Michigan jurisdictional impacts of Tax Reform related to the period January 1, 2018 through August 31, 2018. An order from the MPSC regarding Excess ADIT is expected in the first half of 2019.

Rockport Plant, Unit 2 SCR

In 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements and is expected to be placed in service in May 2020. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer and recover, through a rider, 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.

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.

Management intends to request recovery of the Michigan jurisdictional share of the SCR project in a future base rate case. If the Michigan jurisdictional share of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. The AEGCo ownership share of the SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

<u>KPCo Rate Matters</u> (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. In June 2018, the KPSC issued an order approving an additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June, 2018.

Kentucky Tax Reform

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

<u>OPCo Rate Matters</u> (Applies to AEP and OPCo)

Ohio Electric Security Plan Filings

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

In 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the DIR, effective June 2015 through May 2018.

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

In 2015 and 2016, the PUCO issued orders in this proceeding. As part of the issued orders, the PUCO approved: (a) the DIR with modified revenue caps, (b) recovery of OVEC-related net margin incurred beginning June 2016, (c) potential additional contingent customer credits of up to $15 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MWs and a wind energy project(s) of at least 500 MWs, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects.

In 2017, the PUCO rejected all pending rehearing requests related to the OVEC PPA. In June 2017, intervenors filed appeals to the Supreme Court of Ohio stating that the PUCO's approval of the OVEC PPA was unlawful and does not provide customers with rate stability. In June 2018, oral arguments were held before the Supreme Court of Ohio. In November 2018, the Ohio Supreme Court unanimously affirmed the PUCO's order in the June 2015 - May 2018 ESP and PPA Rider cases.

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

In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In May 2018, OPCo and various intervenors filed requests for rehearing with the PUCO. In June 2018, these requests for rehearing were approved to allow further consideration of the requests. In August 2018, the PUCO denied all requests for rehearing. In October 2018, an appeal was filed with the Ohio Supreme Court challenging various approved riders. If the Ohio Supreme Court reverses the PUCO's decision, it could reduce future net income and cash flows and impact financial condition.

2016 SEET Filing

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

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

A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the first half of 2019. While management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could negatively affect future SEET filings, reduce future net income and cash flows and impact financial condition.

Ohio Tax Reform

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

PSO Rate Matters (Applies to AEP and PSO)

2018 Oklahoma Base Rate Case

In October 2018, PSO filed a request with the OCC for an $88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance-based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase includes $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates includes the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020.

In January 2019, OCC staff and various intervenors filed testimony. OCC staff recommended a $57 million annual rate increase based on a 9% return on common equity while intervenor recommendations ranged from a decrease in rates of $6 million to an increase in rates of $34 million based on a return on common equity ranging from 9.3% to 9.36%, respectively. The difference between PSO's requested annual base rate increase and the OCC staff and intervenors recommendations are primarily due to: (a) a reduction in the requested return on common equity, (b) a rejection to PSO's request to increase depreciation rates, including the proposed accelerated recovery of the Oklaunion Power Station through 2028, (c) a disallowance of certain incentives and operation and maintenance expenses and (d) a proposal to refund Excess ADIT that is not subject to rate normalization requirements over 5 years instead of 10 years. In addition, certain parties recommended a debt only return on, or no recovery of, PSO's estimated remaining net book value in the Oklaunion Power Station after its retirement, which is estimated to be $49 million. Also, a party recommended a potential refund of $9 million related to an SPP rider claiming that PSO did not adequately support the related costs. No parties supported PSO's performance-based rate plan as filed.

In February 2019, PSO filed testimony rebutting the various parties' recommendations included above. PSO also proposed that the performance-based rate plan be implemented on a one-year trial basis where it could be reevaluated at the conclusion of the trial period. In addition, PSO agreed that the prudence of capital investment would be deferred until PSO's next base rate case. A hearing at the OCC is scheduled to begin in March 2019. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Oklahoma Tax Reform

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

<u>SWEPCo Rate Matters</u> (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 a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately $52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals, which was denied. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court.

As of December 31, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% 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 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 was surcharged to customers in 2018 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 was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors.

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

Texas Tax Reform

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

2015 Louisiana Formula Rate Filing

In 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 December 2018, the LPSC issued an order approving the increase as filed.

2017 Louisiana Formula Rate Filing

In 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. Also in 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 were subject to prudence review by the LPSC. In August 2018, the LPSC issued an order affirming prudence and approved the settlement agreement for the environmental control investment. In December 2018, the LPSC issued an order approving the $31 million increase as filed.

2018 Louisiana Formula Rate Filing

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

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

In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. A decision by the LPSC is expected in 2019.

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 December 31, 2018, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of December 31, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $629 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 2017, the LPSC approved recovery of $131 million in investments related to its Louisiana jurisdictional share of environmental controls installed at Welsh Plant. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $10 million, excluding $5 million of unrecognized equity as of December 31, 2018, (b) is subject to review by the LPSC and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. See "2017 Louisiana Formula Rate Filing" and "2018 Louisiana Formula Rate Filing" disclosures above.

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

Arkansas Tax Reform

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

<u>FERC Rate Matters</u>

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

In 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 May 2018, the FERC approved the 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 $98 million to Customer Accounts Receivable and $68 million to Deferred Charges and Other Noncurrent Assets, with offsets to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018.

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

In 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 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 a 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. In February 2019, the FERC issued an order that requested additional information in order to evaluate the settlement. That order did not rule on the merits of the settlement.

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.

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

In 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. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In 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 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. A FERC order set the matter for hearing and settlement procedures. The parties were unable to settle and the proceeding is currently in the hearing phase.

In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. A hearing at the FERC is scheduled for August 2019.

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

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

In 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. The FERC accepted the proposed modifications effective January 1, 2018, subject to refund. In February 2019, AEP's transmission owning subsidiaries within SPP filed an uncontested settlement agreement with the FERC, subject to FERC approval, resolving all outstanding issues. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

In 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. A FERC order set the matter for hearing and settlement procedures.

In July 2018, the FERC issued an order approving a settlement agreement between SWEPCo, ETEC and NTEC that resolves the issues of the complaint. The order: (a) reduced the base return on common equity from 11.1% to 10.1% effective September 1, 2017, (b) required SWEPCo to provide a one-time billing credit of $287 thousand to reflect the decrease in return on common equity from September 1, 2017 through December 31, 2017 and (c) implemented the lower return on common equity on contracts starting January 1, 2018.

5. EFFECTS OF REGULATION

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

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

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. The table below summarizes the plant investment and cost of removal, currently being recovered, as well as the regulatory asset for accelerated depreciation for the generating unit as of December 31, 2018. See "2018 Oklahoma Base Rate Case" section of Note 4 for additional information.

Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset (a)	Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(dollars in millions)				
$ 106.6	$ 62.8	$ 43.8	$ 5.5	$ 3.1	$ 5.0	2020	28 years

(a) In October 2018, PSO changed depreciation rates to utilize the 2020 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously OCC-approved depreciation rates for Oklaunion Power Station. See "2018 Oklahoma Base Rate Case" section of Note 4 for additional information.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining Recovery Period
	2018	2017	
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 101.7	$ 203.1	1 year
Under-recovered Fuel Costs - does not earn a return	48.4	89.4	1 year
Total Current Regulatory Assets	$ 150.1	$ 292.5	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 50.3	$ 50.3	
Kentucky Deferred Purchased Power Expenses	14.5	—	
Other Regulatory Assets Pending Final Regulatory Approval	14.8	9.6	
Total Regulatory Assets Currently Earning a Return	79.6	59.9	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	152.4	128.0	
Plant Retirement Costs - Asset Retirement Obligation Costs	35.3	39.7	
Cook Plant Uprate Project	—	36.3	
Cook Plant Turbine	—	15.9	
Other Regulatory Assets Pending Final Regulatory Approval	20.7	42.2	
Total Regulatory Assets Currently Not Earning a Return	208.4	262.1	
Total Regulatory Assets Pending Final Regulatory Approval (b)	288.0	322.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	680.9	682.6	25 years
Meter Replacement Costs	74.4	83.7	9 years
Plant Retirement Costs - Asset Retirement Obligation Costs	64.3	34.3	22 years

Ohio Capacity Deferral	57.8	172.6	1 year
Advanced Metering System	45.3	33.5	2 years
Environmental Control Projects	43.4	28.1	22 years
Cook Plant Uprate Project	35.0	—	15 years
Storm-Related Costs	31.1	39.3	4 years
Mitchell Plant Transfer - West Virginia	17.0	17.8	22 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	16.1	—	16 years
Cook Plant Turbine	15.8	—	20 years
Ohio Distribution Decoupling	12.3	61.7	2 years
Ohio Basic Transmission Cost Rider	—	90.8	
Other Regulatory Assets Approved for Recovery	46.1	49.4	various
Total Regulatory Assets Currently Earning a Return	1,139.5	1,293.8	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,326.6	1,196.3	12 years
Unamortized Loss on Reacquired Debt	134.2	129.9	30 years
Unrealized Loss on Forward Commitments	104.6	139.3	14 years
Cook Plant Nuclear Refueling Outage Levelization	37.5	66.7	3 years
Postemployment Benefits	35.6	39.1	4 years
Peak Demand Reduction/Energy Efficiency	31.9	40.1	8 years
Medicare Subsidy	27.9	32.5	6 years
Vegetation Management - West Virginia	26.6	33.5	3 years
PJM/SPP Annual Formula Rate True Up	22.0	11.7	2 years
Plant Retirement Costs - Asset Retirement Obligation Costs	21.6	37.2	22 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	20.1	57.0	2 years
Storm-Related Costs	11.3	44.2	5 years
Virginia Transmission Rate Adjustment Clause	—	32.6	
Other Regulatory Assets Approved for Recovery	83.0	111.7	various
Total Regulatory Assets Currently Not Earning a Return	1,882.9	1,971.8	
Total Regulatory Assets Approved for Recovery	3,022.4	3,265.6	
Total Noncurrent Regulatory Assets	$ 3,310.4	$ 3,587.6	

(a) As of December 31, 2018, AEP Texas has deferred $129 million related to Hurricane Harvey and will seek securitization of the distribution related assets. See Note 4 - Rate Matters for additional information.

(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.

Current Regulatory Liabilities	AEP December 31, 2018	AEP December 31, 2017	Remaining Refund Period
	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 35.7	$ 8.7	1 year
Over-recovered Fuel Costs - does not pay a return	22.9	3.2	1 year
Total Current Regulatory Liabilities	$ 58.6	$ 11.9	

Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	2018	2017	Remaining Refund Period
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Currently Not Paying a Return	0.2	0.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	1,025.3	4,256.7	
Excess ADIT that is Not Subject to Rate Normalization Requirements	695.0	1,378.0	
Total Income Tax Related Regulatory Liabilities	1,720.3	5,634.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	1,720.5	5,634.9	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,742.8	2,637.1	(b)
Ohio Basic Transmission Cost Rider	68.8	—	2 years
Excess Earnings	8.9	9.4	35 years
Deferred Investment Tax Credits	8.7	10.6	42 years
Advanced Metering Infrastructure Surcharge	8.5	12.7	2 years
Other Regulatory Liabilities Approved for Payment	0.4	1.3	various
Total Regulatory Liabilities Currently Paying a Return	2,838.1	2,671.1	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	828.5	945.0	(c)
Deferred Investment Tax Credits	204.9	191.2	44 years
PJM Transmission Enhancement Refund	164.2	—	7 years
Transition Charges - Texas	46.0	46.0	6 years
Unrealized Gain on Forward Commitments	45.9	15.0	6 years
Ohio Enhanced Service Reliability Plan	43.1	30.6	2 years
Spent Nuclear Fuel	42.9	43.2	(c)
Peak Demand Reduction/Energy Efficiency	17.5	25.6	3 years
Other Regulatory Liabilities Approved for Payment	84.8	41.6	various
Total Regulatory Liabilities Currently Not Paying a Return	1,477.8	1,338.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	2,925.7	—	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	864.3	—	18 years
Income Taxes Subject to Flow Through	(1,286.1)	(1,221.9)	56 years
Total Income Tax Related Regulatory Liabilities	2,503.9	(1,221.9)	
Total Regulatory Liabilities Approved for Payment	6,819.8	2,787.4	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,540.3	$ 8,422.3	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

Regulatory Assets:	AEP Texas December 31, 2018	2017	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	$ 152.4	$ 123.3	
Rate Case Expense	0.2	0.1	
Total Regulatory Assets Pending Final Regulatory Approval	152.6	123.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Advanced Metering System	45.3	33.5	2 years
Meter Replacement Costs	40.1	44.9	9 years
Total Regulatory Assets Currently Earning a Return	85.4	78.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	176.9	151.2	12 years
Unamortized Loss on Reacquired Debt	6.0	7.7	19 years
Transmission Cost Recovery Factor	1.7	9.5	2 years
Other Regulatory Assets Approved for Recovery	7.4	8.5	various
Total Regulatory Assets Currently Not Earning a Return	192.0	176.9	
Total Regulatory Assets Approved for Recovery	277.4	255.3	
Total Noncurrent Regulatory Assets	$ 430.0	$ 378.7	

(a) As of December 31, 2018, AEP Texas has deferred $129 million related to Hurricane Harvey and will seek securitization of the distribution related assets. See Note 4 - Rate Matters for additional information.

Regulatory Liabilities:	AEP Texas December 31, 2018	2017	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 277.1	$ 578.3	
Excess ADIT that is Not Subject to Rate Normalization Requirements	141.4	103.3	
Total Regulatory Liabilities Pending Final Regulatory Determination	418.5	681.6	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	645.2	599.2	(b)
Advanced Metering Infrastructure Surcharge	8.5	12.7	2 years
Excess Earnings	6.3	6.8	13 years
Total Regulatory Liabilities Currently Paying a Return	660.0	618.7	
Regulatory Liabilities Currently Not Paying a Return			
Transition Charges - Texas	46.0	46.0	6 years
Deferred Investment Tax Credits	10.8	12.3	44 years
Other Regulatory Liabilities Approved for Payment	—	0.6	various
Total Regulatory Liabilities Currently Not Paying a Return	56.8	58.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	251.8	—	(c)
Income Taxes Subject to Flow Through	(42.8)	(38.7)	31 years
Total Income Tax Related Regulatory Liabilities	209.0	(38.7)	
Total Regulatory Liabilities Approved for Payment	925.8	638.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,344.3	$ 1,320.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	AEPTCo December 31, 2018	AEPTCo December 31, 2017	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Not Earning a Return			
PJM/SPP Annual Formula Rate True Up	$ 12.9	$ 11.7	2 years
Total Regulatory Assets Approved for Recovery	12.9	11.7	
Total Noncurrent Regulatory Assets	$ 12.9	$ 11.7	

Regulatory Liabilities:	AEPTCo December 31, 2018	AEPTCo December 31, 2017	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 73.9	$ 512.8	
Excess ADIT that is Not Subject to Rate Normalization Requirements	4.5	(20.6)	
Total Regulatory Liabilities Pending Final Regulatory Determination	78.4	492.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	99.5	66.7	(c)
Total Regulatory Liabilities Currently Paying a Return	99.5	66.7	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	453.4	—	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	(28.5)	—	10 years
Income Taxes Subject to Flow Through (b)	(81.5)	(65.1)	52 years
Total Income Tax Related Regulatory Liabilities	343.4	(65.1)	
Total Regulatory Liabilities Approved for Payment	442.9	1.6	
Total Noncurrent Regulatory Liabilities	$ 521.3	$ 493.8	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.

(b) The 2017 balance reflects the revisions made to AEPTCo's previously issued financial statements. For additional details on the revisions to AEPTCo's financial statements, see Note 1 - Significant Accounting Matters.

(c) Relieved as removal costs are incurred.

(d) Refunded using ARAM.

Regulatory Assets:	APCo December 31, 2018	APCo December 31, 2017	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Virginia - earns a return	$ 82.4	$ 21.4	1 year
Under-recovered Fuel Costs, West Virginia - does not earn a return	17.2	67.4	1 year
Total Current Regulatory Assets	$ 99.6	$ 88.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ 9.0	$ 9.1	
Total Regulatory Assets Currently Earning a Return	9.0	9.1	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	35.3	39.7	
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6	
Total Regulatory Assets Currently Not Earning a Return	35.9	40.3	
Total Regulatory Assets Pending Final Regulatory Approval (a)	44.9	49.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant - West Virginia	85.3	86.3	25 years
West Virginia Delayed Customer Billing	0.6	7.8	1 year
Other Regulatory Assets Approved for Recovery	0.6	3.9	various
Total Regulatory Assets Currently Earning a Return	86.5	98.0	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	172.2	168.8	12 years
Unamortized Loss on Reacquired Debt	89.3	93.2	27 years
Vegetation Management Program - West Virginia	26.6	33.5	3 years
Peak Demand Reduction/Energy Efficiency	19.7	18.1	8 years
Postemployment Benefits	18.0	18.8	4 years
Virginia Generation Rate Adjustment Clause	10.3	7.3	2 years
Virginia Transmission Rate Adjustment Clause	—	32.6	
Storm-Related Costs - West Virginia	—	32.2	
Other Regulatory Assets Approved for Recovery	8.3	22.0	various
Total Regulatory Assets Currently Not Earning a Return	344.4	426.5	
Total Regulatory Assets Approved for Recovery	430.9	524.5	
Total Noncurrent Regulatory Assets	$ 475.8	$ 573.9	

(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.

Regulatory Liabilities:	APCo December 31, 2018	APCo December 31, 2017	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 268.2	$ 794.4	
Excess ADIT that is Not Subject to Rate Normalization Requirements	283.7	381.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	551.9	1,175.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	618.3	615.8	(b)
Deferred Investment Tax Credits	1.0	0.9	42 years
Total Regulatory Liabilities Currently Paying a Return	619.3	616.7	
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	47.7	—	7 years
Unrealized Gain on Forward Commitments	34.7	9.5	6 years
Virginia Transmission Rate Adjustment Clause	11.3	—	2 years
Consumer Rate Relief - West Virginia	8.8	6.5	1 year
Other Regulatory Liabilities Approved for Payment	3.9	1.9	various
Total Regulatory Liabilities Currently Not Paying a Return	106.4	17.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	453.5	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	84.5	—	10 years
Income Taxes Subject to Flow Through	(365.9)	(355.2)	26 years
Total Income Tax Related Regulatory Liabilities	172.1	(355.2)	
Total Regulatory Liabilities Approved for Payment	897.8	279.4	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,449.7	$ 1,454.9	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

(c) Refunded using ARAM.

Regulatory Assets:	I&M December 31, 2018	2017	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ —	$ 15.0	
Total Current Regulatory Assets	$ —	$ 15.0	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Cook Plant Uprate Project	$ —	$ 36.3	
Cook Plant Turbine	—	15.9	
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	—	14.7	
Rockport Plant 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	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	232.2	245.3	10 years
Cook Plant Uprate Project	35.0	—	15 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	16.1	—	16 years
Cook Plant Turbine	15.8	—	20 years
Rockport Plant Dry Sorbent Injection System - Indiana	11.5	—	9 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	5.7	6.0	20 years
Other Regulatory Assets Approved for Recovery	2.4	1.0	various
Total Regulatory Assets Currently Earning a Return	318.7	252.3	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	84.9	77.8	12 years
Cook Plant Nuclear Refueling Outage Levelization	37.5	66.7	3 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	20.1	57.0	2 years
Unamortized Loss on Reacquired Debt	18.7	9.5	30 years
Postemployment Benefits	6.5	9.7	4 years
Medicare Subsidy	6.1	7.1	6 years
Other Regulatory Assets Approved for Recovery	16.7	20.0	various
Total Regulatory Assets Currently Not Earning a Return	190.5	247.8	
Total Regulatory Assets Approved for Recovery	509.2	500.1	
Total Noncurrent Regulatory Assets	$ 512.5	$ 579.4	

Regulatory Liabilities:	I&M December 31, 2018	2017	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Michigan - pays a return	$ 4.5	$ —	1 year
Over-recovered Fuel Costs, Indiana - does not pay a return	22.9	2.7	1 year
Total Current Regulatory Liabilities	$ 27.4	$ 2.7	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 125.0	$ 534.6	
Excess ADIT that is Not Subject to Rate Normalization Requirements	40.6	193.0	
Total Regulatory Liabilities Pending Final Regulatory Determination	165.6	727.6	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	182.5	202.2	(b)
Total Regulatory Liabilities Currently Paying a Return	182.5	202.2	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	828.5	945.0	(c)
Spent Nuclear Fuel	42.9	43.2	(c)
Deferred Investment Tax Credits	29.4	34.1	21 years
PJM Transmission Enhancement Refund	29.1	—	7 years
Other Regulatory Liabilities Approved for Payment	24.0	11.5	various
Total Regulatory Liabilities Currently Not Paying a Return	953.9	1,033.8	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	362.0	—	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	192.6	—	10 years
Income Taxes Subject to Flow Through	(282.1)	(254.9)	26 years
Total Income Tax Related Regulatory Liabilities	272.5	(254.9)	
Total Regulatory Liabilities Approved for Payment	1,408.9	981.1	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,574.5	$ 1,708.7	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

Regulatory Assets:	OPCo December 31, 2018	OPCo December 31, 2017	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 0.4	$ 115.9	1 year
Total Current Regulatory Assets	$ 0.4	$ 115.9	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 1.0	$ —	
Total Regulatory Assets Pending Final Regulatory Approval	1.0	—	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Capacity Deferral	57.8	172.6	1 year
Ohio Distribution Decoupling	12.3	61.7	2 years
Ohio Basic Transmission Cost Rider	—	90.8	
Other Regulatory Assets Approved for Recovery	0.9	1.7	various
Total Regulatory Assets Currently Earning a Return	71.0	326.8	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	181.5	170.6	12 years
Unrealized Loss on Forward Commitments	100.2	131.8	14 years
Smart Grid Costs	8.1	—	2 years
Postemployment Benefits	7.9	7.2	4 years
Unamortized Loss on Reacquired Debt	6.5	7.8	20 years
Other Regulatory Assets Approved for Recovery	11.3	8.6	various
Total Regulatory Assets Currently Not Earning a Return	315.5	326.0	
Total Regulatory Assets Approved for Recovery	386.5	652.8	
Total Noncurrent Regulatory Assets	$ 387.5	$ 652.8	

(a) December 31, 2017 balance includes PIRR.

Regulatory Liabilities:	OPCo December 31, 2018	2017	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Currently Not Paying a Return	0.2	0.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	—	436.3	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	230.8	
Total Income Tax Related Regulatory Liabilities	—	667.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	667.3	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	436.6	428.8	(b)
Ohio Basic Transmission Cost Rider	68.8	—	2 years
Other Regulatory Liabilities Approved for Payment	0.4	1.4	various
Total Regulatory Liabilities Currently Paying a Return	505.8	430.2	
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	71.3	—	7 years
Ohio Enhanced Service Reliability Plan	43.1	30.6	2 years
Peak Demand Reduction/Energy Efficiency	14.9	23.6	2 years
Distribution Investment Rider	7.8	0.3	2 years
Other Regulatory Liabilities Approved for Payment	11.3	11.1	various
Total Regulatory Liabilities Currently Not Paying a Return	148.4	65.6	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	350.5	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	279.1	—	10 years
Income Taxes Subject to Flow Through	(62.8)	(62.9)	29 years
Total Income Tax Related Regulatory Liabilities	566.8	(62.9)	
Total Regulatory Liabilities Approved for Payment	1,221.0	432.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,221.2	$ 1,100.2	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	PSO December 31, 2018	2017	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ —	$ 36.7	
Total Current Regulatory Assets	$ —	$ 36.7	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Oklaunion Power Station Accelerated Depreciation	$ 5.5	$ —	
Total Regulatory Assets Currently Earning a Return	5.5	—	
Regulatory Assets Currently Not Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	0.5	3.3	
Total Regulatory Assets Currently Not Earning a Return	0.5	3.3	
Total Regulatory Assets Pending Final Regulatory Approval	6.0	3.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	153.4	138.5	22 years
Meter Replacement Costs	34.3	38.8	9 years
Storm-Related Costs	31.1	39.0	4 years
Environmental Control Projects	29.2	28.1	22 years
Red Rock Generating Facility	8.6	8.8	38 years
Other Regulatory Assets Approved for Recovery	0.5	0.5	various
Total Regulatory Assets Currently Earning a Return	257.1	253.7	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	84.3	72.7	12 years
Peak Demand Reduction/Energy Efficiency	6.3	13.0	2 years
Unamortized Loss on Reacquired Debt	4.3	5.0	14 years
SPP Base Plan Fees	1.4	16.3	2 years
Other Regulatory Assets Approved for Recovery	9.6	4.1	various
Total Regulatory Assets Currently Not Earning a Return	105.9	111.1	
Total Regulatory Assets Approved for Recovery	363.0	364.8	
Total Noncurrent Regulatory Assets	$ 369.0	$ 368.1	

Regulatory Liabilities:	PSO December 31, 2018	PSO December 31, 2017	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ 20.1	$ —	1 year
Total Current Regulatory Liabilities	$ 20.1	$ —	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ —	$ 447.7	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	92.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	539.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	276.8	268.8	(b)
Total Regulatory Liabilities Currently Paying a Return	276.8	268.8	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	51.5	50.7	26 years
Other Regulatory Liabilities Approved for Payment	2.5	2.3	various
Total Regulatory Liabilities Currently Not Paying a Return	54.0	53.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	415.2	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	126.4	—	10 years
Income Taxes Subject to Flow Through	(7.7)	(8.1)	27 years
Total Income Tax Related Regulatory Liabilities	533.9	(8.1)	
Total Regulatory Liabilities Approved for Payment	864.7	313.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 864.7	$ 853.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See “Federal Tax Reform” section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	SWEPCo December 31, 2018	2017	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Arkansas/Louisiana - earns a return	$ 18.8	$ 14.1	1 year
Total Current Regulatory Assets	$ 18.8	$ 14.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 50.3	$ 50.3	
Other Regulatory Assets Pending Final Regulatory Approval	0.3	0.5	
Total Regulatory Assets Currently Earning a Return	50.6	50.8	
Regulatory Assets Currently Not Earning a Return			
Asset Retirement Obligation - Arkansas, Louisiana	5.3	4.0	
Rate Case Expense - Texas	4.9	4.3	
Shipe Road Transmission Project - FERC	—	3.3	
Other Regulatory Assets Pending Final Regulatory Approval	3.6	2.5	
Total Regulatory Assets Currently Not Earning a Return	13.8	14.1	
Total Regulatory Assets Pending Final Regulatory Approval	64.4	64.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Environmental Controls Projects	14.2	—	14 years
Other Regulatory Assets Approved for Recovery	7.2	7.2	various
Total Regulatory Assets Currently Earning a Return	21.4	7.2	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	108.4	101.0	12 years
Plant Retirement Costs - Unrecovered Plant	17.1	17.6	23 years
Unamortized Loss on Reacquired Debt	7.4	4.7	25 years
Medicare Subsidy	3.2	3.7	6 years
Environmental Controls Projects	—	15.3	
Other Regulatory Assets Approved for Recovery	8.9	6.2	various
Total Regulatory Assets Currently Not Earning a Return	145.0	148.5	
Total Regulatory Assets Approved for Recovery	166.4	155.7	
Total Noncurrent Regulatory Assets	$ 230.8	$ 220.6	

	SWEPCo		
	December 31,		Remaining Refund Period
	2018	2017	
Regulatory Liabilities:	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Texas - pays a return	$ 11.1	$ 8.7	1 year
Total Current Regulatory Liabilities	$ 11.1	$ 8.7	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 280.1	$ 650.5	
Excess ADIT that is Not Subject to Rate Normalization Requirements	26.9	62.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	307.0	713.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	437.8	424.5	(b)
Other Regulatory Liabilities Approved for Payment	2.5	2.6	various
Total Regulatory Liabilities Currently Paying a Return	440.3	427.1	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	4.5	5.9	13 years
Other Regulatory Liabilities Approved for Payment	4.9	7.5	various
Total Regulatory Liabilities Currently Not Paying a Return	9.4	13.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	370.5	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	54.3	—	2 years
Income Taxes Subject to Flow Through	(258.5)	(257.3)	31 years
Total Income Tax Related Regulatory Liabilities	166.3	(257.3)	
Total Regulatory Liabilities Approved for Payment	616.0	183.2	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 923.0	$ 896.4	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See “Federal Tax Reform” section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

6. 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.

COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

The AEP System has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2018:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,081.7	$ 1,020.7	$ 306.7	$ 135.0	$ 2,544.1
Energy and Capacity Purchase Contracts	239.7	463.6	324.3	1,337.2	2,364.8
Total	$ 1,321.4	$ 1,484.3	$ 631.0	$ 1,472.2	$ 4,908.9

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 391.8	$ 390.1	$ 8.4	$ 0.5	$ 790.8
Energy and Capacity Purchase Contracts	37.0	72.0	74.0	317.7	500.7
Total	$ 428.8	$ 462.1	$ 82.4	$ 318.2	$ 1,291.5

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 251.4	$ 293.1	$ 187.8	$ 83.8	$ 816.1
Energy and Capacity Purchase Contracts	126.8	264.0	166.4	322.3	879.5
Total	$ 378.2	$ 557.1	$ 354.2	$ 406.1	$ 1,695.6

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 31.0	$ 59.2	$ 60.2	$ 338.6	$ 489.0

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 58.4	$ 69.7	$ 20.1	$ —	$ 148.2
Energy and Capacity Purchase Contracts	93.0	182.2	75.3	226.2	576.7
Total	$ 151.4	$ 251.9	$ 95.4	$ 226.2	$ 724.9

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 108.8	$ 132.1	$ 32.6	$ —	$ 273.5
Energy and Capacity Purchase Contracts	33.4	62.4	50.2	125.8	271.8
Total	$ 142.2	$ 194.5	$ 82.8	$ 125.8	$ 545.3

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

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 $4 billion revolving credit facility due in June 2022, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2018, no letters of credit were issued under the 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 December 31, 2018 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 60.6	January 2019 to December 2019
AEP Texas (a)	2.8	January 2019
OPCo	0.6	September 2019

(a) In January 2019, the letter of credit was amended to $2.2 million and the maturity date was extended until January 2020.

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

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

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $140 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon depletion of reserves and completion of reclamation. The reserves are estimated to deplete in 2036 with reclamation completed by 2046 at an estimated cost of $107 million. Actual reclamation costs could vary due to inflation and scope changes to the mine reclamation. As of December 31, 2018, SWEPCo has collected $75 million through a rider for reclamation costs, of which $80 million was recorded in Asset Retirement Obligations, offset by $5 million recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

Sabine charges all of its costs to its only customer, SWEPCo, which recovers these costs through its fuel clauses.

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 December 31, 2018, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

Indemnifications and Other Guarantees

Contracts

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

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

Lease Obligations

Certain Registrants lease equipment under master lease agreements. See "Master Lease Agreements", "Railcar Lease" and "AEPRO Boat and Barge Leases" sections of Note 13 for additional information.

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 non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2018, APCo and OPCo are named as a Potentially Responsible Party (PRP) for one and three sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at two sites under state law including the site discussed in the next paragraph. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. The remediation work was completed in 2018 in accordance with a plan approved by MDEQ with no significant effects on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2018, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

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

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2018. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2 billion in 2018 non-discounted dollars, with additional ongoing costs of $6 million per year for post decommissioning storage of SNF and an eventual cost of $37 million for the subsequent decommissioning of the SNF storage facility, also in 2018 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $8 million, $9 million and $9 million for the years ended December 31, 2018, 2017 and 2016, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2018 and 2017, the total decommissioning trust fund balances were $2.2 billion and $2.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2018 and 2017, fees and related interest of $274 million and $269 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $317 million and $312 million, respectively, to pay the fee were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $11 million, $22 million and $6 million in 2018, 2017 and 2016, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December

31, 2018 and 2017, I&M deferred $8 million and $11 million, respectively, in Prepayments and Other Current Assets and $23 million and $5 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel Disposal" section of Note 11 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover an incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by an extraordinary incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $1.5 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $50 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $14.1 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $450 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $276 million per nuclear incident on Cook Plant's reactors payable in annual installments of $41 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $450 million through commercially available insurance. The next level of liability coverage of up to $13.6 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

The Registrants maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. The Registrants also maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by the Registrants. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers. See "Nuclear Contingencies" section above for additional information.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

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, refueling 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. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices 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.

The U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims, and remanding the case for further proceedings.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. Responsive and supplemental filings have been made by all parties. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to the consent decree. See "Proposed Modification of the NSR Litigation Consent Decree" section of Management's Discussion and Analysis of Financial Condition and Results of Operations 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.

7. DISPOSITIONS AND IMPAIRMENTS

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

DISPOSITIONS

2017

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 years ended December 31, 2017 and 2016.

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 statements 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 statements of income for the year ended December 31, 2017.

2016

Tanners Creek Plant (Vertically Integrated Utilities Segment) (Applies to AEP and I&M)

In October 2016, I&M sold its retired Tanners Creek Plant site including its associated AROs to a nonaffiliated party. I&M paid $92 million and the nonaffiliated party took ownership of the Tanners Creek plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. I&M did not record a gain or loss related to this sale. In 2018, the MPSC and IURC approved the recovery of the additional costs associated with the sale of Tanners Creek Plant over the remaining useful life of Rockport, Unit 1. If any of the costs associated with Tanners Creek are not recoverable, it could reduce future net income and impact financial condition.

Wind Farms (Applies to AEP Texas)

In December 2016, TCC and TNC merged into AEP Utilities, Inc. Prior to the merger, AEP Utilities, Inc. was a subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. CSW Energy, Inc. owns Desert Sky and Trent (collectively "Wind Farms"). Upon merger, AEP Utilities, Inc. changed its name to AEP Texas. Subsequent to the merger, AEP Texas exited the merchant generation business by transferring all of the common stock of the Wind Farms to a competitive AEP affiliate. No gain or loss was recognized and no cash was exchanged related to the disposition of the Wind Farms.

In the fourth quarter of 2016, the Wind Farms were determined to be discontinued operations. Accordingly, results of operations of the Wind Farms have been classified as discontinued operations on AEP Texas' statements of income for the year ended December 31, 2016 as shown in the following table:

	Year Ended December 31, 2016
	(in millions)
Revenue	$ 18.2
Other Operation Expense	6.5
Maintenance Expense	3.4
Asset Impairment and Other Related Charges	72.7
Depreciation and Amortization Expense	9.8
Taxes Other Than Income Taxes	1.3
Total Expenses	93.7
Other Income (Expense)	(0.8)
Pretax Loss of Discontinued Operations	(76.3)
Income Tax Benefit	(27.5)
Total Loss on Discontinued Operations as Presented on the Statements of Income	$ (48.8)

IMPAIRMENTS

2018

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 statements of income related to the equity investment and related assets. The impairment also had an immaterial impact to APCo.

Merchant Generating Assets (Generation & Marketing Segment)

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017 and reconstruction activities continued throughout 2018. An initial impairment recorded related to Racine is discussed in the "2017" section below.

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

2017

Merchant Generating Assets (Generation & Marketing Segment)

In 2017, AEP recorded an additional pretax impairment of $4 million in Asset Impairments and Other Related Charges on AEP's statements of income related to Cardinal, Unit 1, a 43.5% interest in Conesville, Unit 4, Conesville, Units 5 and 6, a 26% interest in Stuart, Units 1-4, a 25.4% interest in Zimmer, Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets"). The initial impairment recorded related to these assets is discussed in the "2016" section below. In addition, AEP recorded a $7 million pretax impairment as Asset Impairments and Other Related Charges on AEP's statements of income related to the sale of Zimmer Plant. The sale is further discussed in the "Disposition" section of this note.

Due to a significant increase in estimated costs identified in December 2017 to repair a defective dam structure at Racine, AEP performed an impairment analysis on Racine in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a fair value determination for Racine of $0 and AEP recorded a pretax impairment of $43 million in Assets Impairments and Other Related Charges on the statements of income in the fourth quarter of 2017.

Welsh Plant, Unit 2 and Turk Plant (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)

In December 2017, SWEPCo recorded a pretax impairment of $19 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional share of Welsh Plant, Unit 2 and other disallowed plant investments. Additionally in December 2017, SWEPCo recorded a pretax impairment of $15 million in Asset Impairments and Other Related Charges on the statements of income related to the Louisiana jurisdictional share of the Turk Plant. See the "2016 Texas Base Rate Case" section of Note 4.

2016

Merchant Generating Assets (Generation & Marketing Segment)

In September 2016, due to AEP's ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP's existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. The Merchant Coal-Fired Generation Assets were subject to this analysis. Additionally, Racine, Putnam and I&M's Price River coal reserves ("Coal Reserves") and the Wind Farms were also included in this analysis. For the Merchant Coal-Fired Generation Assets, Racine and the Wind Farms, AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful lives of the assets based upon energy and capacity price curves, as applicable, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step one analysis concluded the book value of Racine would be recovered and the book value of the remaining assets would not be recovered.

AEP performed step two of the impairment analysis on the Merchant Coal-Fired Generation Assets using a ten-year discounted cash flow model based upon forecasted energy and capacity price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step two analysis resulted in projected negative cash flows. Based on this result, coupled with the significant capital investments necessary to comply with environmental rules to allow the Merchant Coal-Fired Generation Assets to operate to the end of their currently estimated depreciable lives and the joint-ownership structure of these facilities, management determined the fair value of these assets was $0. AEP performed step two of the impairment analysis on the Wind Farms using a ten-year discounted cash flow model utilizing forecasted energy price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The results concluded the Wind Farms were also impaired.

For the Coal Reserves, AEP performed step one of the impairment analysis and concluded the book value of the assets would not be recovered. Step two of the impairment analysis on the Coal Reserves was performed using a market approach with Level 3 unobservable inputs. The results concluded the Coal Reserves were also impaired.

Based on the impairment analysis performed, in the third quarter of 2016, AEP recorded a pretax impairment of $2.3 billion in Asset Impairments and Other Related Charges on the statements of income. See the table below for additional information.

Impaired Assets	Book Value	Fair Value	Impairment
		(in millions)	
Merchant Coal-Fired Generation Assets	$ 2,139.4	$ —	$ 2,139.4
Desert Sky and Trent	118.7	46.0	72.7
Coal Reserves (a)	56.6	3.8	52.8
Total	$ 2,314.7	$ 49.8	$ 2,264.9

(a) Includes the $11 million book value of I&M's Price River Coal Reserves which were fully impaired. This $11 million impairment is reflected in the Vertically Integrated Utilities Segment.

Based on capital expenditure activity of the Merchant Coal-fired Generation Assets in the fourth quarter of 2016, AEP recorded a pretax impairment of an additional $3 million in Asset Impairments and Other Related Charges on AEP's statements of income.

8. BENEFIT PLANS

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

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

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.

Due to the Registrant Subsidiaries' participation in AEP's benefits plans, the assumptions used by the actuary, with the exception of the rate of compensation increase, and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrants and the rate of compensation increase for each Registrant.

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. The Registrants recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of the Registrants' benefit obligations are shown in the following tables:

	Pension Plans		OPEB	
	December 31,			
Assumption	2018	2017	2018	2017
Discount Rate	4.30%	3.65%	4.30%	3.60%
Interest Crediting Rate	4.00%	4.00%	NA	NA

NA Not applicable.

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	2018	2017
AEP	4.85%	4.80%
AEP Texas	4.95%	4.90%
APCo	4.75%	4.60%
I&M	4.90%	4.85%
OPCo	5.00%	4.95%
PSO	4.90%	4.90%
SWEPCo	4.85%	4.80%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant.

For 2018, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of each Registrants' benefit costs are shown in the following tables:

	Pension Plans			OPEB		
	Year Ended December 31,					
Assumption	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Discount Rate	3.65%	4.05%	4.30%	3.60%	4.10%	4.30%
Interest Crediting Rate	4.00%	4.00%	4.00%	NA	NA	NA
Expected Return on Plan Assets	6.00%	6.00%	6.00%	6.00%	6.75%	7.00%

NA Not applicable.

	Pension Plans		
	Year Ended December 31,		
Assumption – Rate of Compensation Increase (a)	**2018**	**2017**	**2016**
AEP	4.85%	4.80%	4.75%
AEP Texas	4.95%	4.90%	4.85%
APCo	4.75%	4.60%	4.55%
I&M	4.90%	4.85%	4.80%
OPCo	5.00%	4.95%	4.85%
PSO	4.90%	4.90%	4.90%
SWEPCo	4.85%	4.80%	4.75%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third party forecasts and current prospects for economic growth. The expected return on plan assets is the same for each Registrant.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	December 31,	
Health Care Trend Rates	**2018**	**2017**
Initial	6.25%	6.50%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	2024

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2018, the assets were invested in compliance with all investment limits. See “Investments Held in Trust for Future Liabilities” section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans. For the year ended December 31, 2017, the pension plans had an actuarial loss due to a decrease in the discount rate. The OPEB plans had an actuarial gain primarily due to a change in medical benefits for retirees which was partially offset by a decrease in the discount rate. The following tables provide a reconciliation of the changes in the plans’ benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP	**Pension Plans**		**OPEB**	
	2018	**2017**	**2018**	**2017**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 5,215.8	$ 5,085.8	$ 1,332.0	$ 1,447.4
Service Cost	97.6	96.5	11.6	11.2
Interest Cost	187.8	203.1	47.4	59.3
Actuarial (Gain) Loss	(306.3)	182.4	(100.1)	(97.5)
Benefit Payments	(384.6)	(352.0)	(133.6)	(128.6)
Participant Contributions	—	—	36.5	39.5
Medicare Subsidy	—	—	0.7	0.7
Benefit Obligation as of December 31,	$ 4,810.3	$ 5,215.8	$ 1,194.5	$ 1,332.0
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 5,174.1	$ 4,827.3	$ 1,732.5	$ 1,545.9
Actual Gain (Loss) on Plan Assets	(104.9)	600.0	(118.3)	271.6
Company Contributions (a)	11.3	98.8	17.1	4.1
Participant Contributions	—	—	36.5	39.5
Benefit Payments	(384.6)	(352.0)	(133.6)	(128.6)
Fair Value of Plan Assets as of December 31,	$ 4,695.9	$ 5,174.1	$ 1,534.2	$ 1,732.5
Funded (Underfunded) Status as of December 31,	$ (114.4)	$ (41.7)	$ 339.7	$ 400.5

(a) Contributions to the qualified pension plan were $0 and $93 million for the years ended December 31, 2018 and 2017, respectively. Contributions to the nonqualified pension plans were $11 million and $6 million for the years ended December 31, 2018 and 2017, respectively.

AEP	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ 36.3	$ 392.2	$ 463.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(5.7)	(6.2)	(2.8)	(3.2)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(108.7)	(71.8)	(49.7)	(59.3)
Funded (Underfunded) Status	$ (114.4)	$ (41.7)	$ 339.7	$ 400.5

AEP Texas	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 441.3	$ 421.7	$ 107.1	$ 120.4
Service Cost	9.2	8.6	0.9	0.9
Interest Cost	16.0	17.1	3.8	4.9
Actuarial (Gain) Loss	(20.9)	25.6	(8.3)	(11.9)
Benefit Payments	(36.3)	(31.7)	(10.7)	(10.8)
Participant Contributions	—	—	3.1	3.6
Benefit Obligation as of December 31,	$ 409.3	$ 441.3	$ 95.9	$ 107.1
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 455.9	$ 416.6	$ 147.3	$ 134.1
Actual Gain (Loss) on Plan Assets	(9.3)	61.8	(14.6)	20.4
Company Contributions	0.4	9.2	4.8	—
Participant Contributions	—	—	3.1	3.6
Benefit Payments	(36.3)	(31.7)	(10.7)	(10.8)
Fair Value of Plan Assets as of December 31,	$ 410.7	$ 455.9	$ 129.9	$ 147.3
Funded Status as of December 31,	$ 1.4	$ 14.6	$ 34.0	$ 40.2

AEP Texas	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 5.2	$ 18.6	$ 34.0	$ 40.2
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(3.4)	(3.6)	—	—
Funded Status	$ 1.4	$ 14.6	$ 34.0	$ 40.2

APCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 665.0	$ 654.0	$ 236.5	$ 255.6
Service Cost	9.3	9.4	1.1	1.1
Interest Cost	23.5	25.7	8.2	10.6
Actuarial (Gain) Loss	(49.2)	15.7	(21.9)	(13.4)
Benefit Payments	(45.5)	(39.8)	(24.7)	(24.3)
Participant Contributions	—	—	6.1	6.7
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 603.1	$ 665.0	$ 205.5	$ 236.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 651.7	$ 606.4	$ 273.4	$ 246.9
Actual Gain (Loss) on Plan Assets	(12.9)	74.9	(18.7)	41.6
Company Contributions	—	10.2	2.3	2.5
Participant Contributions	—	—	6.1	6.7
Benefit Payments	(45.5)	(39.8)	(24.7)	(24.3)
Fair Value of Plan Assets as of December 31,	$ 593.3	$ 651.7	$ 238.4	$ 273.4
Funded (Underfunded) Status as of December 31,	$ (9.8)	$ (13.3)	$ 32.9	$ 36.9

	Pension Plans		OPEB	
	December 31,			
APCo	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 62.3	$ 74.6
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.1)	(2.5)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(9.8)	(13.3)	(27.3)	(35.2)
Funded (Underfunded) Status	$ (9.8)	$ (13.3)	$ 32.9	$ 36.9

I&M	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 624.3	$ 611.6	$ 153.5	$ 167.6
Service Cost	13.6	14.0	1.6	1.6
Interest Cost	22.1	24.3	5.4	6.9
Actuarial (Gain) Loss	(53.9)	10.8	(10.6)	(12.0)
Benefit Payments	(39.1)	(36.4)	(16.2)	(15.6)
Participant Contributions	—	—	4.5	4.9
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 567.0	$ 624.3	$ 138.3	$ 153.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 636.7	$ 586.1	$ 211.1	$ 186.6
Actual Gain (Loss) on Plan Assets	(13.8)	74.0	(12.1)	35.2
Company Contributions	—	13.0	—	—
Participant Contributions	—	—	4.5	4.9
Benefit Payments	(39.1)	(36.4)	(16.2)	(15.6)
Fair Value of Plan Assets as of December 31,	$ 583.8	$ 636.7	$ 187.3	$ 211.1
Funded Status as of December 31,	$ 16.8	$ 12.4	$ 49.0	$ 57.6

	Pension Plans		OPEB	
	December 31,			
I&M	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 18.0	$ 13.4	$ 49.0	$ 57.6
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.2)	(1.0)	—	—
Funded Status	$ 16.8	$ 12.4	$ 49.0	$ 57.6

OPCo	Pension Plans		OPEB	
	2018	**2017**	**2018**	**2017**
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 501.1	$ 492.9	$ 144.3	$ 164.0
Service Cost	7.7	7.5	0.9	0.9
Interest Cost	17.7	19.4	5.1	6.7
Actuarial (Gain) Loss	(36.6)	13.1	(9.4)	(16.6)
Benefit Payments	(36.0)	(31.8)	(15.8)	(15.5)
Participant Contributions	—	—	4.3	4.7
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 453.9	$ 501.1	$ 129.5	$ 144.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 509.1	$ 473.8	$ 198.5	$ 182.6
Actual Gain (Loss) on Plan Assets	(7.0)	58.9	(11.6)	26.7
Company Contributions	—	8.2	—	—
Participant Contributions	—	—	4.3	4.7
Benefit Payments	(36.0)	(31.8)	(15.8)	(15.5)
Fair Value of Plan Assets as of December 31,	$ 466.1	$ 509.1	$ 175.4	$ 198.5
Funded Status as of December 31,	$ 12.2	$ 8.0	$ 45.9	$ 54.2

	Pension Plans		OPEB	
	December 31,			
OPCo	**2018**	**2017**	**2018**	**2017**
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 12.6	$ 8.4	$ 45.9	$ 54.2
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.4)	(0.4)	—	—
Funded Status	$ 12.2	$ 8.0	$ 45.9	$ 54.2

PSO	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 276.6	$ 266.7	$ 69.4	$ 77.6
Service Cost	7.0	6.4	0.7	0.7
Interest Cost	9.9	10.7	2.5	3.2
Actuarial (Gain) Loss	(18.9)	10.1	(5.6)	(7.5)
Benefit Payments	(20.8)	(17.3)	(6.7)	(6.9)
Participant Contributions	—	—	2.0	2.3
Benefit Obligation as of December 31,	$ 253.8	$ 276.6	$ 62.3	$ 69.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 287.8	$ 266.0	$ 95.5	$ 86.4
Actual Gain (Loss) on Plan Assets	(5.9)	33.6	(9.2)	13.7
Company Contributions	0.1	5.5	2.7	—
Participant Contributions	—	—	2.0	2.3
Benefit Payments	(20.8)	(17.3)	(6.7)	(6.9)
Fair Value of Plan Assets as of December 31,	$ 261.2	$ 287.8	$ 84.3	$ 95.5
Funded Status as of December 31,	$ 7.4	$ 11.2	$ 22.0	$ 26.1

	Pension Plans		OPEB	
	December 31,			
PSO	2018	2017	2018	2017
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 9.7	$ 13.9	$ 22.0	$ 26.1
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.2)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(2.1)	(2.5)	—	—
Funded Status	$ 7.4	$ 11.2	$ 22.0	$ 26.1

SWEPCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 314.6	$ 296.6	$ 80.3	$ 86.9
Service Cost	9.3	8.7	0.9	0.9
Interest Cost	11.3	12.3	2.8	3.6
Actuarial (Gain) Loss	(19.2)	16.3	(5.9)	(6.2)
Benefit Payments	(24.6)	(19.3)	(7.7)	(7.4)
Participant Contributions	—	—	2.3	2.5
Benefit Obligation as of December 31,	$ 291.4	$ 314.6	$ 72.7	$ 80.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 311.7	$ 287.3	$ 110.4	$ 96.8
Actual Gain (Loss) on Plan Assets	(7.3)	34.6	(9.2)	18.5
Company Contributions	1.2	9.1	2.7	—
Participant Contributions	—	—	2.3	2.5
Benefit Payments	(24.6)	(19.3)	(7.7)	(7.4)
Fair Value of Plan Assets as of December 31,	$ 281.0	$ 311.7	$ 98.5	$ 110.4
Funded (Underfunded) Status as of December 31,	$ (10.4)	$ (2.9)	$ 25.8	$ 30.1

	Pension Plans		OPEB	
	December 31,			
SWEPCo	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 25.8	$ 30.1
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.2)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(10.2)	(2.7)	—	—
Funded (Underfunded) Status	$ (10.4)	$ (2.9)	$ 25.8	$ 30.1

Amounts Included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense and the items attributable to the change in these components:

AEP	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 1,355.2	$ 1,354.2	$ 419.8	$ 309.9
Prior Service Credit	—	—	(347.2)	(416.3)
Recorded as				
Regulatory Assets	$ 1,267.9	$ 1,271.3	$ 52.5	$ (82.4)
Deferred Income Taxes	18.4	17.4	4.2	(5.0)
Net of Tax AOCI	68.9	53.9	15.9	(15.6)
Income Tax Expense (a)	—	11.6	—	(3.4)

AEP	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 88.8	$ (132.8)	$ 120.4	$ (267.8)
Amortization of Actuarial Loss	(87.8)	(82.8)	(10.5)	(36.7)
Amortization of Prior Service Credit (Cost)	—	(1.0)	69.1	69.1
Change for the Year Ended December 31,	$ 1.0	$ (216.6)	$ 179.0	$ (235.4)

AEP Texas	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 182.0	$ 175.2	$ 38.0	$ 23.9
Prior Service Credit	—	—	(29.5)	(35.4)
Recorded as				
Regulatory Assets	$ 168.2	$ 161.4	$ 8.7	$ (10.2)
Deferred Income Taxes	2.9	2.9	—	(0.3)
Net of Tax AOCI	10.9	8.9	(0.2)	(0.8)
Income Tax Expense (a)	—	2.0	—	(0.2)

AEP Texas	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 14.0	$ (11.1)	$ 14.9	$ (23.6)
Amortization of Actuarial Loss	(7.2)	(7.0)	(0.8)	(3.2)
Amortization of Prior Service Credit	—	—	5.9	5.8
Change for the Year Ended December 31,	$ 6.8	$ (18.1)	$ 20.0	$ (21.0)

APCo

Components	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 172.2	$ 182.5	$ 58.9	$ 48.0
Prior Service Credit	—	—	(50.4)	(60.4)
Recorded as				
Regulatory Assets	$ 169.6	$ 179.9	$ 2.6	$ (11.1)
Deferred Income Taxes	0.5	0.5	1.2	(0.3)
Net of Tax AOCI	2.1	1.7	4.7	(0.8)
Income Tax Expense (a)	—	0.4	—	(0.2)

APCo

Components	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 0.3	$ (23.3)	$ 12.8	$ (38.6)
Amortization of Actuarial Loss	(10.6)	(10.4)	(1.9)	(6.3)
Amortization of Prior Service Credit (Cost)	—	(0.2)	10.0	10.1
Change for the Year Ended December 31,	$ (10.3)	$ (33.9)	$ 20.9	$ (34.8)

I&M

Components	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 80.6	$ 94.9	$ 54.7	$ 42.0
Prior Service Credit	—	—	(47.4)	(56.9)
Recorded as				
Regulatory Assets	$ 78.4	$ 91.8	$ 6.5	$ (14.0)
Deferred Income Taxes	0.5	0.7	0.2	(0.2)
Net of Tax AOCI	1.7	2.0	0.6	(0.6)
Income Tax Expense (a)	—	0.4	—	(0.1)

I&M

Components	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	(in millions)			
Actuarial (Gain) Loss During the Year	$ (4.5)	$ (28.6)	$ 13.9	$ (34.9)
Amortization of Actuarial Loss	(9.8)	(9.7)	(1.2)	(4.4)
Amortization of Prior Service Credit (Cost)	—	(0.2)	9.5	9.4
Change for the Year Ended December 31,	$ (14.3)	$ (38.5)	$ 22.2	$ (29.9)

OPCo	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 180.7	$ 189.6	$ 35.5	$ 22.6
Prior Service Credit	—	—	(34.7)	(41.6)
Recorded as				
Regulatory Assets	$ 180.7	$ 189.6	$ 0.8	$ (19.0)

OPCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (0.9)	$ (18.0)	$ 14.0	$ (31.3)
Amortization of Actuarial Loss	(8.0)	(7.8)	(1.1)	(4.3)
Amortization of Prior Service Credit (Cost)	—	(0.1)	6.9	6.9
Change for the Year Ended December 31,	$ (8.9)	$ (25.9)	$ 19.8	$ (28.7)

PSO	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 77.6	$ 78.8	$ 28.3	$ 19.8
Prior Service Credit	—	—	(21.6)	(25.9)
Recorded as				
Regulatory Assets	$ 77.6	$ 78.8	$ 6.7	$ (6.1)

PSO	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 3.2	$ (7.9)	$ 9.0	$ (15.5)
Amortization of Actuarial Loss	(4.4)	(4.3)	(0.5)	(2.0)
Amortization of Prior Service Credit	—	—	4.3	4.3
Change for the Year Ended December 31,	$ (1.2)	$ (12.2)	$ 12.8	$ (13.2)

SWEPCo	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 97.4	$ 97.4	$ 33.9	$ 24.7
Prior Service Credit	—	—	(26.2)	(31.4)
Recorded as				
Regulatory Assets	$ 97.4	$ 97.4	$ 4.9	$ (3.7)
Deferred Income Taxes	—	—	0.7	(0.6)
Net of Tax AOCI	—	—	2.1	(2.0)
Income Tax Expense (a)	—	—	—	(0.4)

SWEPCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 5.5	$ (1.5)	$ 9.8	$ (18.4)
Amortization of Actuarial Loss	(5.5)	(4.9)	(0.6)	(2.3)
Amortization of Prior Service Credit (Cost)	—	(0.1)	5.2	5.2
Change for the Year Ended December 31,	$ —	$ (6.5)	$ 14.4	$ (15.5)

(a) Amounts relate to the re-measurement of Deferred Income Taxes as a result of Tax Reform. In accordance with the accounting guidance for "Income Taxes", re-measurement of Deferred Income Taxes related to AOCI must flow through the statement of income.

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to the Registrant Subsidiaries using the percentages in the table below:

	Pension Plan		OPEB	
	December 31,			
Company	2018	2017	2018	2017
AEP Texas	8.7%	8.8%	8.5%	8.5%
APCo	12.6%	12.6%	15.5%	15.8%
I&M	12.4%	12.3%	12.2%	12.2%
OPCo	9.9%	9.8%	11.4%	11.5%
PSO	5.6%	5.6%	5.5%	5.5%
SWEPCo	6.0%	6.0%	6.4%	6.4%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 277.3	$ —	$ —	$ —	$ 277.3	5.9%
International	384.1	—	—	—	384.1	8.2%
Options	—	18.3	—	—	18.3	0.4%
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9%
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4%
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2%
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0%
Foreign Debt	—	221.6	—	—	221.6	4.7%
State and Local Government	—	28.2	—	—	28.2	0.6%
Other – Asset Backed	—	7.4	—	—	7.4	0.2%
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7%
Infrastructure (c)	—	—	—	72.2	72.2	1.5%
Real Estate (c)	—	—	—	220.4	220.4	4.7%
Alternative Investments (c)	—	—	—	444.6	444.6	9.5%
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0%
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2%
Total	$ 661.2	$ 2,907.2	$ —	$ 1,127.5	$ 4,695.9	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 233.3	$ —	$ —	$ —	$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
Total	$ 515.6	$ 625.2	$ —	$ 393.4	$ 1,534.2	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 318.6	$ —	$ —	$ —	$ 318.6	6.2%
International	507.7	—	—	—	507.7	9.8%
Options	—	26.9	—	—	26.9	0.5%
Common Collective Trusts (c)	—	—	—	452.9	452.9	8.7%
Subtotal – Equities	826.3	26.9	—	452.9	1,306.1	25.2%
Fixed Income (a):						
United States Government and Agency Securities	—	1,376.5	—	—	1,376.5	26.6%
Corporate Debt	—	1,277.0	—	—	1,277.0	24.7%
Foreign Debt	—	296.9	—	—	296.9	5.7%
State and Local Government	—	31.7	—	—	31.7	0.6%
Other – Asset Backed	—	10.2	—	—	10.2	0.2%
Subtotal – Fixed Income	—	2,992.3	—	—	2,992.3	57.8%
Infrastructure (c)	—	—	—	59.5	59.5	1.2%
Real Estate (c)	—	—	—	290.3	290.3	5.6%
Alternative Investments (c)	—	—	—	446.0	446.0	8.6%
Cash and Cash Equivalents (c)	0.4	35.6	—	21.2	57.2	1.1%
Other – Pending Transactions and Accrued Income (b)	—	—	—	22.7	22.7	0.5%
Total	$ 826.7	$ 3,054.8	$ —	$ 1,292.6	$ 5,174.1	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Infrastructure	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2017	$ 57.6	$ 254.9	$ 411.1	$ 723.6
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	—	—	—	—
Relating to Assets Sold During the Period	—	—	—	—
Purchases and Sales	—	—	—	—
Transfers into Level 3	—	—	—	—
Transfers out of Level 3 (a)	(57.6)	(254.9)	(411.1)	(723.6)
Balance as of December 31, 2017	$ —	$ —	$ —	$ —

(a) The classification of Level 3 assets from the prior year was corrected in the current year presentation and included within the fair value hierarchy table as of December 31, 2017 as "Other" investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). Management concluded that these disclosure errors were immaterial individually and in the aggregate to all prior periods presented.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 307.1	$ —	$ —	$ —	$ 307.1	17.7 %
International	306.9	—	—	—	306.9	17.7 %
Options	—	9.4	—	—	9.4	0.5 %
Common Collective Trusts (b)	—	—	—	153.6	153.6	8.9 %
Subtotal – Equities	614.0	9.4	—	153.6	777.0	44.8 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	185.0	185.0	10.7 %
United States Government and Agency Securities	—	187.4	—	—	187.4	10.8 %
Corporate Debt	—	214.1	—	—	214.1	12.4 %
Foreign Debt	—	40.7	—	—	40.7	2.4 %
State and Local Government	49.7	16.8	—	—	66.5	3.8 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	49.7	459.2	—	185.0	693.9	40.1 %
Trust Owned Life Insurance:						
International Equities	—	105.4	—	—	105.4	6.1 %
United States Bonds	—	118.2	—	—	118.2	6.8 %
Subtotal – Trust Owned Life Insurance	—	223.6	—	—	223.6	12.9 %
Cash and Cash Equivalents (b)	36.7	—	—	4.2	40.9	2.4 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.9)	(2.9)	(0.2)%
Total	$ 700.4	$ 692.2	$ —	$ 339.9	$ 1,732.5	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,560.7	$ 393.2	$ 588.3	$ 536.3	$ 438.3	$ 238.0	$ 271.6
Nonqualified Pension Plans	64.9	3.6	0.2	0.6	0.2	2.2	1.2
Total as of December 31, 2018	$ 4,625.6	$ 396.8	$ 588.5	$ 536.9	$ 438.5	$ 240.2	$ 272.8

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,951.3	$ 421.4	$ 648.0	$ 592.4	$ 483.4	$ 256.9	$ 289.4
Nonqualified Pension Plans	73.9	3.8	0.2	0.4	0.1	2.7	2.2
Total as of December 31, 2017	$ 5,025.2	$ 425.2	$ 648.2	$ 592.8	$ 483.5	$ 259.6	$ 291.6

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 4,810.3	$ 3.8	$ 603.1	$ 1.2	$ 0.4	$ 2.3	$ 291.4
Fair Value of Plan Assets	4,695.9	—	593.3	—	—	—	281.0
Underfunded Projected Benefit Obligation as of December 31, 2018	$ (114.4)	$ (3.8)	$ (9.8)	$ (1.2)	$ (0.4)	$ (2.3)	$ (10.4)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 78.0	$ 4.0	$ 665.0	$ 1.0	$ 0.4	$ 2.7	$ 314.6
Fair Value of Plan Assets	—	—	651.7	—	—	—	311.7
Underfunded Projected Benefit Obligation as of December 31, 2017	$ (78.0)	$ (4.0)	$ (13.3)	$ (1.0)	$ (0.4)	$ (2.7)	$ (2.9)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 64.9	$ 3.6	$ 0.2	$ 0.6	$ 0.2	$ 2.2	$ 1.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2018	$ (64.9)	$ (3.6)	$ (0.2)	$ (0.6)	$ (0.2)	$ (2.2)	$ (1.2)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 73.9	$ 3.8	$ 0.2	$ 0.4	$ 0.1	$ 2.7	$ 2.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2017	$ (73.9)	$ (3.8)	$ (0.2)	$ (0.4)	$ (0.1)	$ (2.7)	$ (2.2)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2019:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 98.7	$ 4.5
AEP Texas	8.0	0.1
APCo	7.7	2.1
I&M	1.1	—
OPCo	0.5	—
PSO	0.2	—
SWEPCo	7.9	—

The tables below reflect the total benefits expected to be paid from the plan or from the Registrants' assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2019	$ 339.8	$ 30.8	$ 43.4	$ 36.2	$ 34.3	$ 19.0	$ 21.4
2020	344.2	34.3	42.8	36.4	34.5	19.5	21.8
2021	354.2	34.9	43.4	37.5	34.0	21.2	22.9
2022	357.3	33.5	43.6	38.9	33.9	20.4	23.8
2023	364.1	34.9	44.2	40.3	34.7	23.1	24.0
Years 2024 to 2028, in Total	1,808.2	164.7	220.2	210.6	163.3	102.5	120.5

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2019	$ 122.0	$ 10.0	$ 22.0	$ 14.8	$ 14.5	$ 6.3	$ 7.1
2020	126.5	10.5	22.5	15.4	14.8	6.8	7.5
2021	127.1	10.7	22.2	15.7	14.8	6.8	7.8
2022	127.2	10.9	22.1	15.7	14.7	7.0	8.0
2023	126.3	10.9	21.6	15.6	14.5	7.1	8.1
Years 2024 to 2028, in Total	618.8	53.6	103.4	75.6	69.1	34.9	41.5

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2019	$ 0.2	$ —	$ 0.2	$ —	$ —	$ —	$ —
2020	0.2	—	0.2	—	—	—	—
2021	0.3	—	0.2	—	—	—	—
2022	0.3	—	0.2	—	—	—	—
2023	0.3	—	0.2	—	—	—	—
Years 2024 to 2028, in Total	1.5	—	0.7	—	—	—	—

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		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 97.6	$ 96.5	$ 85.8	$ 11.6	$ 11.2	$ 10.2
Interest Cost	187.8	203.1	211.6	47.4	59.3	60.9
Expected Return on Plan Assets	(290.3)	(284.8)	(280.3)	(102.2)	(101.3)	(107.0)
Amortization of Prior Service Cost (Credit)	—	1.0	2.3	(69.1)	(69.1)	(69.0)
Amortization of Net Actuarial Loss	85.2	82.8	83.8	10.5	36.7	31.4
Settlements	2.6	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	82.9	98.6	103.2	(101.8)	(63.2)	(73.5)
Capitalized Portion	(41.1)	(39.9)	(37.8)	(4.9)	25.6	26.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 41.8	$ 58.7	$ 65.4	$ (106.7)	$ (37.6)	$ (46.6)

AEP Texas

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 9.2	$ 8.6	$ 7.5	$ 0.9	$ 0.9	$ 0.7
Interest Cost	16.0	17.1	17.8	3.8	4.9	5.1
Expected Return on Plan Assets	(25.6)	(25.0)	(24.5)	(8.6)	(8.8)	(9.3)
Amortization of Prior Service Cost (Credit)	—	—	0.4	(5.9)	(5.8)	(6.0)
Amortization of Net Actuarial Loss	7.2	7.0	7.1	0.8	3.2	2.8
Net Periodic Benefit Cost (Credit)	6.8	7.7	8.3	(9.0)	(5.6)	(6.7)
Capitalized Portion	(4.8)	(4.0)	(3.6)	(0.5)	2.9	3.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2.0	$ 3.7	$ 4.7	$ (9.5)	$ (2.7)	$ (3.3)

APCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 9.3	$ 9.4	$ 8.1	$ 1.1	$ 1.1	$ 1.0
Interest Cost	23.5	25.7	27.2	8.2	10.6	10.8
Expected Return on Plan Assets	(36.6)	(35.8)	(35.3)	(16.0)	(16.5)	(17.3)
Amortization of Prior Service Cost (Credit)	—	0.2	0.1	(10.0)	(10.1)	(10.1)
Amortization of Net Actuarial Loss	10.6	10.4	10.8	1.9	6.3	5.4
Net Periodic Benefit Cost (Credit)	6.8	9.9	10.9	(14.8)	(8.6)	(10.2)
Capitalized Portion	(3.8)	(4.0)	(4.1)	(0.5)	3.5	3.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.0	$ 5.9	$ 6.8	$ (15.3)	$ (5.1)	$ (6.3)

I&M

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 13.6	$ 14.0	$ 12.2	$ 1.6	$ 1.6	$ 1.5
Interest Cost	22.1	24.3	25.3	5.4	6.9	7.0
Expected Return on Plan Assets	(35.7)	(34.6)	(33.6)	(12.3)	(12.2)	(12.9)
Amortization of Prior Service Cost (Credit)	—	0.2	0.1	(9.5)	(9.4)	(9.4)
Amortization of Net Actuarial Loss	9.8	9.7	10.0	1.2	4.4	3.7
Net Periodic Benefit Cost (Credit)	9.8	13.6	14.0	(13.6)	(8.7)	(10.1)
Capitalized Portion	(5.6)	(5.5)	(3.3)	(0.7)	3.5	2.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 4.2	$ 8.1	$ 10.7	$ (14.3)	$ (5.2)	$ (7.7)

OPCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 7.7	$ 7.5	$ 6.5	$ 0.9	$ 0.9	$ 0.8
Interest Cost	17.7	19.4	20.6	5.1	6.7	7.0
Expected Return on Plan Assets	(28.8)	(27.9)	(27.6)	(11.7)	(11.9)	(13.0)
Amortization of Prior Service Cost (Credit)	—	0.1	0.1	(6.9)	(6.9)	(6.9)
Amortization of Net Actuarial Loss	8.0	7.8	8.1	1.1	4.3	3.8
Net Periodic Benefit Cost (Credit)	4.6	6.9	7.7	(11.5)	(6.9)	(8.3)
Capitalized Portion	(3.6)	(3.3)	(3.4)	(0.4)	3.3	3.7
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1.0	$ 3.6	$ 4.3	$ (11.9)	$ (3.6)	$ (4.6)

PSO	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 7.0	$ 6.4	$ 6.2	$ 0.7	$ 0.7	$ 0.6
Interest Cost	9.9	10.7	11.2	2.5	3.2	3.3
Expected Return on Plan Assets	(16.1)	(15.6)	(15.5)	(5.6)	(5.6)	(6.1)
Amortization of Prior Service Cost (Credit)	—	—	0.3	(4.3)	(4.3)	(4.3)
Amortization of Net Actuarial Loss	4.4	4.3	4.4	0.5	2.0	1.8
Net Periodic Benefit Cost (Credit)	5.2	5.8	6.6	(6.2)	(4.0)	(4.7)
Capitalized Portion	(2.6)	(2.1)	(2.4)	(0.3)	1.4	1.7
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2.6	$ 3.7	$ 4.2	$ (6.5)	$ (2.6)	$ (3.0)

SWEPCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 9.3	$ 8.7	$ 8.1	$ 0.9	$ 0.9	$ 0.8
Interest Cost	11.3	12.3	12.4	2.8	3.6	3.6
Expected Return on Plan Assets	(17.3)	(17.0)	(16.4)	(6.4)	(6.3)	(6.8)
Amortization of Prior Service Cost (Credit)	—	0.1	0.3	(5.2)	(5.2)	(5.0)
Amortization of Net Actuarial Loss	5.1	4.9	4.8	0.6	2.3	1.9
Settlements	0.4	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	8.8	9.0	9.2	(7.3)	(4.7)	(5.5)
Capitalized Portion	(3.1)	(2.7)	(2.7)	(0.3)	1.4	1.6
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 5.7	$ 6.3	$ 6.5	$ (7.6)	$ (3.3)	$ (3.9)

American Electric Power System Retirement Savings Plan

AEP sponsors the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not covered by a retirement savings plan of the UMWA. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant:

	Year Ended December 31,		
Company	**2018**	**2017**	**2016**
	(in millions)		
AEP	$ 71.8	$ 74.6	$ 72.9
AEP Texas	5.7	6.0	5.2
APCo	7.5	7.4	7.3
I&M	10.5	10.7	10.9
OPCo	6.3	6.1	5.6
PSO	4.5	5.0	4.3
SWEPCo	5.9	6.0	5.7

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan was in Critical and Declining Status for the plan years ending June 30, 2018 and 2017, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in February 2015 which was updated in 2016, 2017 and April 2018.

The amounts contributed by AEP affiliates in 2018, 2017 and 2016 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2017. UMWA pension contributions included a surcharge of 10% from July 2015 through June 2016 at which time new base contribution rates went into effect with no associated surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the December 31, 2020 expiration of the current collective bargaining agreement between the Cook Coal Terminal (CCT) facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

Based upon the planned closure of CCT in 2022, AEP records a UMWA pension withdrawal liability on the balance sheet. The UMWA pension withdrawal liability is re-measured annually and is the estimated value of the company's proportionate share of the plan's unfunded vested liabilities. As of December 31, 2018 and 2017, the liability balance was $15 million and $19 million, respectively. AEP recovers the estimated UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. As of December 31, 2018, AEP recorded a regulatory liability on the balance sheets for $3 million and as of December 31, 2017, AEP recorded a regulatory asset on the balance sheets for $1 million. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. 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 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, interest expense, income tax expense and other nonallocated costs.

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2018, 2017 and 2016 and reportable segment balance sheet information as of December 31, 2018 and 2017.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2018							
Revenues from:							
External Customers	$ 9,556.7	$ 4,552.3	$ 248.6	$ 1,818.1	$ 20.0	$ —	$ 16,195.7
Other Operating Segments	88.8	100.8	555.5	122.2	75.1	(942.4)	—
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7
Asset Impairments and Other Related Charges	$ 3.4	$ —	$ —	$ 47.7	$ 19.5	$ —	$ 70.6
Depreciation and Amortization	1,316.2	734.1	137.8	41.0	0.4	57.1 (b)	2,286.6
Interest and Investment Income	11.7	4.2	2.5	13.1	31.0	(50.9)	11.6
Carrying Costs Income (Expense)	5.3	1.7	(0.4)	—	—	—	6.6
Interest Expense	567.8	248.1	90.7	14.9	122.6	(59.7) (b)	984.4
Income Tax Expense (Benefit)	5.7	42.4	95.3	(49.2)	21.1	—	115.3
Net Income (Loss)	$ 995.5	$ 527.4	$ 373.0	$ 134.7	$ (99.3)	$ —	$ 1,931.3
Gross Property Additions	$ 2,282.2	$ 2,162.4	$ 1,614.1	$ 289.7	$ 16.3	$ (39.2)	$ 6,325.5
Total Property, Plant and Equipment	$ 45,365.1	$ 18,126.7	$ 8,659.5	$ 893.3	$ 395.2	$ (354.6) (b)	$ 73,085.2
Accumulated Depreciation and Amortization	13,822.5	3,833.7	282.8	47.0	186.6	(186.5) (b)	17,986.1
Total Property, Plant and Equipment – Net	$ 31,542.6	$ 14,293.0	$ 8,376.7	$ 846.3	$ 208.6	$ (168.1) (b)	$ 55,099.1
Total Assets	$ 38,874.3	$ 17,083.4	$ 9,543.7	$ 1,979.7	$ 4,036.5 (c)	$ (2,714.8) (b) (d)	$ 68,802.8
Investments in Equity Method Investees	$ 39.6	$ 2.9	$ 750.9	$ 26.7	$ 26.1	$ —	$ 846.2
Long-term Debt Due Within One Year:							
Nonaffiliated	$ 1,066.3	$ 549.1	$ 85.0	$ 0.1	$ (2.0) (e)	$ —	$ 1,698.5
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	11,442.7	5,048.8	2,888.6	(0.3)	2,268.4 (e)	—	21,648.2
Total Long-term Debt	$ 12,559.0	$ 5,597.9	$ 2,973.6	$ 32.0	$ 2,266.4	$ (82.2)	$ 23,346.7

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	$ 9,095.1	$ 4,328.9	$ 178.4	$ 1,771.4	$ 51.1	$ —	$ 15,424.9
Other Operating Segments	96.9	90.4	588.3	103.7	69.7	(949.0)	—
Total Revenues	$ 9,192.0	$ 4,419.3	$ 766.7	$ 1,875.1	$ 120.8	$ (949.0)	$ 15,424.9
Asset Impairments and Other Related Charges	$ 33.6	$ —	$ —	$ 53.5	$ —	$ —	$ 87.1
Depreciation and Amortization	1,142.5	667.5	102.2	24.2	0.3	60.5 (b)	1,997.2
Interest and Investment Income	6.8	7.7	1.2	10.3	23.3	(33.3)	16.0
Carrying Costs Income (Expense)	15.2	3.6	(0.2)	—	—	—	18.6
Interest Expense	540.0	244.1	72.8	18.5	63.9	(44.3) (b)	895.0
Income Tax Expense	425.6	127.2	189.8	189.7	37.4	—	969.7
Net Income (Loss)	$ 803.3	$ 636.4	$ 355.6	$ 166.0	$ (32.4)	$ —	$ 1,928.9
Gross Property Additions	$ 2,343.2	$ 1,558.4	$ 1,542.8	$ 328.5	$ 15.6	$ (90.4)	$ 5,698.1
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
Investments in Equity Method Investees	$ 37.1	$ 1.5	$ 742.9	$ 16.6	$ 14.2	$ —	$ 812.3
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

2016	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other(a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 9,012.4	$ 4,328.3	$ 145.9	$ 2,858.7	$ 34.8	$ —	$ 16,380.1
Other Operating Segments	79.5	94.1	366.9	127.3	70.3	(738.1)	—
Total Revenues	$ 9,091.9	$ 4,422.4	$ 512.8	$ 2,986.0	$ 105.1	$ (738.1)	$ 16,380.1
Asset Impairments and Other Related Charges	$ 10.5	$ —	$ —	$ 2,257.3	$ —	$ —	$ 2,267.8
Depreciation and Amortization	1,073.8	649.9	67.1	154.6	0.2	16.7 (b)	1,962.3
Interest and Investment Income	4.8	14.8	0.4	1.4	11.8	(16.9)	16.3
Carrying Costs Income (Expense)	10.5	20.0	(0.3)	—	—	(14.0)	16.2
Interest Expense	522.1	256.9	50.3	35.8	40.5	(28.4) (b)	877.2
Income Tax Expense (Benefit)	397.3	205.1	134.1	(666.5)	(143.7)	—	(73.7)
Income (Loss) from Continuing Operations	984.0	482.1	269.3	(1,198.0)	83.1	—	620.5
Income (Loss) from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$ 984.0	$ 482.1	$ 269.3	$ (1,198.0)	$ 80.6	$ —	$ 618.0
Gross Property Additions	$ 2,237.0	$ 1,058.3	$ 1,265.8	$ 336.2	$ 9.8	$ (18.1)	$ 4,889.0
Total Assets	$ 37,428.3	$ 14,802.4	$ 6,384.8	$ 3,386.1	$ 3,883.4 (c)	$ (2,417.3) (b) (d)	$ 63,467.7

(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, 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.
(e) Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 for additional information.

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. 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 years ended December 31, 2018, 2017 and 2016 and reportable segment balance sheet information as of December 31, 2018 and 2017.

2018	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 177.0	$ —	$ —	$ 177.0
Sales to AEP Affiliates	598.9	—	—	598.9
Other Revenues	0.2	—	—	0.2
Total Revenues	$ 776.1	$ —	$ —	$ 776.1
Depreciation and Amortization	$ 133.9	$ —	$ —	$ 133.9
Interest Income	1.3	104.6	(103.4) (a)	2.5
Allowance for Equity Funds Used During Construction	70.6	—	—	70.6
Interest Expense	83.2	103.4	(103.4) (a)	83.2
Income Tax Expense	83.9	0.2	—	84.1
Net Income	$ 314.9	$ 1.0 (b)	$ —	$ 315.9
Gross Property Additions	$ 1,570.8	$ —	$ —	$ 1,570.8
Total Transmission Property	$ 8,268.1	$ —	$ —	$ 8,268.1
Accumulated Depreciation and Amortization	271.9	—	—	271.9
Total Transmission Property - Net	$ 7,996.2	$ —	$ —	$ 7,996.2
Notes Receivable - Affiliated	$ —	$ 2,823.0	$ (2,823.0) (c)	$ —
Total Assets	$ 8,406.8	$ 2,857.1 (d)	$ (2,869.8) (e)	$ 8,394.1
Total Long-Term Debt	$ 2,850.0	$ 2,823.0	$ (2,850.0) (c)	$ 2,823.0

2017	State Transcos (f)	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated (f)
		(in millions)		
Revenues from:				
External Customers	$ 138.0	$ —	$ —	$ 138.0
Sales to AEP Affiliates	568.1	—	—	568.1
Other Revenues	0.8	—	—	0.8
Total Revenues	$ 706.9	$ —	$ —	$ 706.9
Depreciation and Amortization	$ 95.7	$ —	$ —	$ 95.7
Interest Income	0.7	82.9	(82.4) (a)	1.2
Allowance for Equity Funds Used During Construction	49.0	—	—	49.0
Interest Expense	70.2	82.4	(82.4) (a)	70.2
Income Tax Expense	142.0	0.2	—	142.2
Net Income	$ 270.4	$ 0.3 (b)	$ —	$ 270.7
Gross Property Additions	$ 1,522.5	$ —	$ —	$ 1,522.5
Total Transmission Property	$ 6,770.5	$ —	$ —	$ 6,770.5
Accumulated Depreciation and Amortization	152.6	—	—	152.6
Total Transmission Property - Net	$ 6,617.9	$ —	$ —	$ 6,617.9
Notes Receivable - Affiliated	$ —	$ 2,550.4	$ (2,550.4) (c)	$ —
Total Assets	$ 7,086.9	$ 2,590.1 (d)	$ (2,594.9) (e)	$ 7,082.1
Total Long-Term Debt	$ 2,575.0	$ 2,550.4	$ (2,575.0) (c)	$ 2,550.4

2016	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 110.4	$ —	$ —	$ 110.4
Sales to AEP Affiliates	367.5	—	—	367.5
Other	0.1	—	—	0.1
Total Revenues	$ 478.0	$ —	$ —	$ 478.0
Depreciation and Amortization	$ 65.9	$ —	$ —	$ 65.9
Interest Income	0.1	57.8	(57.5) (a)	0.4
Allowance for Equity Funds Used During Construction	52.3	—	—	52.3
Interest Expense	45.6	57.9	(57.5) (a)	46.0
Income Tax Expense (Benefit)	94.4	(0.3)	—	94.1
Net Income (Loss)	$ 193.3	$ (0.6) (b)	$ —	$ 192.7
Gross Property Additions	$ 1,166.0	$ —	$ —	$ 1,166.0
Total Assets	$ 5,337.5	$ 1,987.7 (d)	$ (1,975.4) (e)	$ 5,349.8

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Includes elimination of AEPTCo Parent's equity earnings in the State Transcos.
(c) Elimination of intercompany debt.
(d) Includes elimination of AEPTCo Parent's investments in the State Transcos.
(e) Primarily relates to elimination of Notes Receivable from the State Transcos.
(f) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

10. 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
December 31, 2018

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	371.1	—	66.4	40.9	7.8	15.2	4.5
Natural Gas	MMBtus	87.9	—	4.0	2.3	—	—	15.2
Heating Oil and Gasoline	Gallons	7.4	1.5	1.4	0.7	1.8	0.7	0.8
Interest Rate	USD	$ 37.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2017

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

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

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

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. AEP netted cash collateral received from third parties against short-term and long-term risk management assets in the amounts of $18 million and $9.4 million as of December 31, 2018 and 2017, respectively. AEP netted cash collateral paid to third parties against short-term and long-term risk management liabilities in the amounts of $4 million and $9 million as of December 31, 2018 and 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 December 31, 2018 and 2017.

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

AEP

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 397.5	$ 28.5	$ —	$ 426.0	$ (263.2)	$ 162.8
Long-term Risk Management Assets	276.4	16.0	—	292.4	(38.4)	254.0
Total Assets	673.9	44.5	—	718.4	(301.6)	416.8
Current Risk Management Liabilities	293.8	13.2	2.0	309.0	(254.0)	55.0
Long-term Risk Management Liabilities	225.7	56.1	15.4	297.2	(33.8)	263.4
Total Liabilities	519.5	69.3	17.4	606.2	(287.8)	318.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 154.4	$ (24.8)	$ (17.4)	$ 112.2	$ (13.8)	$ 98.4

Fair Value of Derivative Instruments
December 31, 2017

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

AEP Texas

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	0.7	(0.5)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.7	(0.5)	0.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.7)	$ 0.5	$ (0.2)

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 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
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 114.4	$ (57.2)	$ 57.2
Long-term Risk Management Assets	3.1	(2.2)	0.9
Total Assets	117.5	(59.4)	58.1
Current Risk Management Liabilities	56.7	(56.3)	0.4
Long-term Risk Management Liabilities	2.4	(2.2)	0.2
Total Liabilities	59.1	(58.5)	0.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 58.4	$ (0.9)	$ 57.5

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	$ 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
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 50.4	$ (41.8)	$ 8.6
Long-term Risk Management Assets	2.0	(1.4)	0.6
Total Assets	52.4	(43.2)	9.2
Current Risk Management Liabilities	41.1	(40.8)	0.3
Long-term Risk Management Liabilities	1.6	(1.5)	0.1
Total Liabilities	42.7	(42.3)	0.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 9.7	$ (0.9)	$ 8.8

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
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	6.4	(0.6)	5.8
Long-term Risk Management Liabilities	93.8	—	93.8
Total Liabilities	100.2	(0.6)	99.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ (100.2)	$ 0.6	$ (99.6)

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	$ 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
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 10.9	$ (0.5)	$ 10.4
Long-term Risk Management Assets	—	—	—
Total Assets	10.9	(0.5)	10.4
Current Risk Management Liabilities	1.7	(0.7)	1.0
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	1.7	(0.7)	1.0
Total MTM Derivative Contract Net Assets	$ 9.2	$ 0.2	$ 9.4

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
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 5.6	$ (0.8)	$ 4.8
Long-term Risk Management Assets	—	—	—
Total Assets	5.6	(0.8)	4.8
Current Risk Management Liabilities	1.5	(1.1)	0.4
Long-term Risk Management Liabilities	2.2	—	2.2
Total Liabilities	3.7	(1.1)	2.6
Total MTM Derivative Contract Net Assets	$ 1.9	$ 0.3	$ 2.2

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 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
Year Ended December 31, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Vertically Integrated Utilities Revenues	$ (10.4)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	38.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(1.9)	(8.2)	—	—	0.1
Purchased Electricity for Resale	8.6	—	7.6	0.8	—	—	—
Other Operation	1.7	0.4	0.2	0.2	0.3	0.2	0.2
Maintenance	1.9	0.4	0.4	0.2	0.4	0.2	0.2
Regulatory Assets (a)	27.9	(0.7)	(0.7)	7.1	24.9	(1.1)	(1.2)
Regulatory Liabilities (a)	222.7	(0.5)	135.5	11.6	—	37.3	11.9
Total Gain (Loss) on Risk Management Contracts	$ 291.3	$ (0.4)	$ 141.1	$ 11.7	$ 25.6	$ 36.6	$ 11.2

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Year Ended December 31, 2017

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Vertically Integrated Utilities Revenues	$ 6.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	42.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.6	5.3	—	—	0.1
Purchased Electricity for Resale	5.6	—	2.0	0.6	—	—	—
Other Operation	0.8	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.7	0.2	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	(29.4)	—	—	(7.4)	(22.0)	—	0.3
Regulatory Liabilities (a)	109.4	0.1	40.4	15.9	—	24.8	24.3
Total Gain (Loss) on Risk Management Contracts	$ 136.0	$ 0.4	$ 43.2	$ 14.6	$ (21.8)	$ 25.0	$ 24.9

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Year Ended December 31, 2016

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Vertically Integrated Utilities Revenues	$ 4.0	$ —	$ —	$ —	$ —	$ —	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—	—
Generation & Marketing Revenues	59.4	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.6)	4.1	0.1	—	—
Sales to AEP Affiliates	—	—	2.1	5.8	—	—	—
Purchased Electricity for Resale	6.6	—	3.5	0.3	—	—	—
Other Operation	(1.6)	(0.4)	(0.1)	(0.1)	(0.3)	(0.1)	(0.3)
Maintenance	(1.8)	(0.4)	(0.4)	(0.1)	(0.4)	(0.2)	(0.2)
Regulatory Assets (a)	(117.4)	0.8	0.6	3.1	(127.7)	0.4	5.2
Regulatory Liabilities (a)	79.1	0.4	51.4	13.9	(15.2)	6.5	15.7
Total Gain (Loss) on Risk Management Contracts	$ 28.4	$ 0.4	$ 56.5	$ 27.0	$ (143.5)	$ 6.6	$ 20.4

(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)	
	December 31, 2018	**December 31, 2017**	**December 31, 2018**	**December 31, 2017**
	(in millions)			
Long-Term Debt (a)	$ (478.3)	$ (489.3)	$ 17.4	$ 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:

	Twelve Months Ended December 31,		
	2018	**2017**	**2016**
	(in millions)		
Gain (Loss) on Interest Rate Contracts:			
Gain (Loss) on Fair Value Hedging Instruments (a)	$ (11.3)	$ (4.8)	$ 1.6
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	11.3	4.8	(1.6)

(a) Gain (Loss) is included in Interest Expense on the statements of income.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2018, 2017 and 2016, AEP applied cash flow hedging to outstanding power derivatives. During the years ended 2018, 2017 and 2016, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the years ended 2018, 2017 and 2016, AEP applied cash flow hedging to outstanding interest rate derivatives. During the years ended 2017 and 2016, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2018, SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the years ended 2018, 2017 and 2016, 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

	December 31, 2018		December 31, 2017	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (23.0)	$ (12.6)	$ (28.4)	$ (13.0)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	10.4	(1.1)	5.5	(0.8)

As of December 31, 2018 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 180 months.

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

	December 31, 2018		December 31, 2017	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (4.4)	$ (1.1)	$ (4.5)	$ (0.9)
APCo	1.8	0.9	2.2	0.7
I&M	(11.5)	(1.6)	(10.7)	(1.3)
OPCo	1.0	1.0	1.9	1.1
PSO	2.1	1.0	2.6	0.8
SWEPCo	(3.3)	(1.5)	(6.0)	(1.4)

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

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. 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 no derivative contracts with collateral triggering events in a net liability position as of December 31, 2018 and 2017.

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:

	December 31, 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	$ 225.5	$ 1.8	$ 181.0
APCo	0.9	—	—
I&M	0.5	—	—
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

11. FAIR VALUE MEASUREMENTS

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

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:

	December 31,			
	2018		2017	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP	$ 23,346.7	$ 24,093.9	$ 21,173.3	$ 23,649.6
AEP Texas	3,881.3	3,964.6	3,649.3	3,964.8
AEPTCo	2,823.0	2,782.4	2,550.4	2,782.9
APCo	4,062.6	4,473.3	3,980.1	4,782.6
I&M	3,035.4	3,070.2	2,745.1	3,014.7
OPCo	1,716.6	1,919.7	1,719.3	2,064.3
PSO	1,287.0	1,361.9	1,286.5	1,457.1
SWEPCo	2,713.4	2,670.2	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. See "Other Temporary Investments" section of Note 1 for additional information.

The following is a summary of Other Temporary Investments:

	December 31, 2018			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 230.6	$ —	$ —	$ 230.6
Fixed Income Securities – Mutual Funds (b)	106.6	—	(2.3)	104.3
Equity Securities – Mutual Funds	17.8	16.4	—	34.2
Total Other Temporary Investments	$ 355.0	$ 16.4	$ (2.3)	$ 369.1

	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:

	Years Ended December 31, 2018	2017	2016
		(in millions)	
Proceeds from Investment Sales	$ —	$ —	$ —
Purchases of Investments	3.1	14.2	2.3
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 years ended December 31, 2018, 2017 and 2016, see Note 3 - Comprehensive Income.

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

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments:

	December 31, 2018			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	$ 22.5	$ —	$ —	$ 17.2	$ —	$ —
Fixed Income Securities:						
United States Government	996.1	26.7	(7.1)	981.2	29.7	(3.6)
Corporate Debt	52.4	1.1	(1.9)	58.7	3.8	(1.2)
State and Local Government	8.6	0.6	(0.2)	8.8	0.8	(0.2)
Subtotal Fixed Income Securities	1,057.1	28.4	(9.2)	1,048.7	34.3	(5.0)
Equity Securities – Domestic (a)	1,395.3	766.3	—	1,461.7	868.2	(75.5)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,474.9	$ 794.7	$ (9.2)	$ 2,527.6	$ 902.5	$ (80.5)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $784 million and unrealized losses of $18 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:

	Years Ended December 31, 2018	2017	2016
		(in millions)	
Proceeds from Investment Sales	$ 2,010.0	$ 2,256.3	$ 2,957.7
Purchases of Investments	2,064.7	2,300.5	3,000.0
Gross Realized Gains on Investment Sales	47.5	200.7	46.1
Gross Realized Losses on Investment Sales	32.8	146.0	24.4

The base cost of fixed income securities was $1 billion and $1 billion as of December 31, 2018 and 2017, respectively. The base cost of equity securities was $629 million and $594 million as of December 31, 2018 and 2017, respectively.

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

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 359.4
After 1 year through 5 years	358.9
After 5 years through 10 years	176.1
After 10 years	162.7
Total	$ 1,057.1

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

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
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 221.5	$ —	$ —	$ 9.1	$ 230.6
Fixed Income Securities – Mutual Funds	104.3	—	—	—	104.3
Equity Securities – Mutual Funds (b)	34.2	—	—	—	34.2
Total Other Temporary Investments	360.0	—	—	9.1	369.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.8	326.5	340.9	(288.5)	382.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.1	12.7	(2.7)	34.1
Total Risk Management Assets	3.8	350.6	353.6	(291.2)	416.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities – Domestic (b)	1,395.3	—	—	—	1,395.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,771.4	$ 1,407.7	$ 353.6	$ (271.9)	$ 3,260.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 4.2	$ 327.0	$ 185.6	$ (274.7)	$ 242.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.8	36.8	(2.7)	58.9
Fair Value Hedges	—	17.4	—	—	17.4
Total Risk Management Liabilities	$ 4.2	$ 369.2	$ 222.4	$ (277.4)	$ 318.4

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

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
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
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 156.7	$ —	$ —	$ —	$ 156.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.7	$ —	$ (0.5)	$ 0.2

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
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 25.6	$ —	$ —	$ —	$ 25.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	0.1	59.1	58.3	(59.4)	58.1
Total Assets	$ 25.7	$ 59.1	$ 58.3	$ (59.4)	$ 83.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 0.2	$ 58.4	$ 0.5	$ (58.5)	$ 0.6

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

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 42.1	$ 10.3	$ (43.2)	$ 9.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities – Domestic (b)	1,395.3	—	—	—	1,395.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,407.6	$ 1,099.2	$ 10.3	$ (33.0)	$ 2,484.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 0.1	$ 41.2	$ 1.4	$ (42.3)	$ 0.4

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

OPCo

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 27.6	$ —	$ —	$ —	$ 27.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.8	$ 99.4	$ (0.6)	$ 99.6

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
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 10.8	$ (0.4)	$ 10.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 1.3	$ (0.6)	$ 1.0

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
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 5.6	$ (0.8)	$ 4.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 3.3	$ (1.1)	$ 2.6

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 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 December 31, 2018 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(4) million in 2019, $1 million in periods 2020-2022, $1 million in periods 2023-2024 and $1 million in periods 2025-2032; Level 3 matures $108 million in 2019, $37 million in periods 2020-2022, $23 million in periods 2023-2024 and $(12) million in periods 2025-2032. 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 years ended December 31, 2018, 2017 and 2016.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 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) (b) (c)	148.9	104.1	14.2	1.8	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 (b)	9.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	15.7	—	—	—	—	—
Settlements	(214.0)	(127.9)	(21.3)	4.6	(24.3)	(2.1)
Transfers into Level 3 (d) (e)	15.8	—	—	—	—	—
Transfers out of Level 3 (e)	(1.6)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	116.3	56.9	8.7	26.6	9.5	3.3
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3

Year Ended December 31, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	37.3	17.2	4.0	(1.4)	3.1	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	33.6	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(18.8)	—	—	—	—	—
Settlements	(50.6)	(18.9)	(7.1)	7.4	(3.8)	(6.8)
Transfers into Level 3 (d) (e)	16.2	—	—	—	—	—
Transfers out of Level 3 (e)	(10.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	30.2	25.0	7.9	(19.4)	6.2	6.0
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9

Year Ended December 31, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2015	$ 146.9	$ 11.7	$ 4.3	$ 15.9	$ 0.6	$ 0.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	42.8	25.6	7.1	(3.0)	(1.0)	7.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	26.1	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(23.0)	—	—	—	—	—
Settlements	(71.4)	(37.5)	(11.1)	6.2	0.4	(8.4)
Transfers into Level 3 (d) (e)	13.3	—	—	—	—	—
Transfers out of Level 3 (e)	(2.6)	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(129.6)	1.5	2.4	(138.1)	0.7	0.6
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on the statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities or accounts payable.

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

Significant Unobservable Inputs
December 31, 2018

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 257.1	$ 212.5	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 176.57	$ 33.07
Natural Gas Contracts	—	2.5	Discounted Cash Flow	Forward Market Price (b)	2.18	3.54	2.47
FTRs	96.5	7.4	Discounted Cash Flow	Forward Market Price (a)	(11.68)	17.79	1.09
Total	$ 353.6	$ 222.4					

Significant Unobservable Inputs
December 31, 2017

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	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
Natural Gas Contracts	—	0.2	Discounted Cash Flow	Forward Market Price (b)	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
December 31, 2018

APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 2.4	$ 0.5	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	55.9	—	Discounted Cash Flow	Forward Market Price	0.10	15.16	3.27
Total	$ 58.3	$ 0.5					

Significant Unobservable Inputs
December 31, 2017

APCo

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.8	$ 0.4	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	24.3	—	Discounted Cash Flow	Forward Market Price	(0.36)	7.15	1.62
Total	$ 25.1	$ 0.4					

Significant Unobservable Inputs
December 31, 2018

I&M

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 1.4	$ 0.9	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	8.9	0.5	Discounted Cash Flow	Forward Market Price	(2.11)	6.21	1.06
Total	$ 10.3	$ 1.4					

Significant Unobservable Inputs
December 31, 2017

I&M

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	8.6	1.2	Discounted Cash Flow	Forward Market Price	(0.36)	5.75	0.86
Total	$ 9.1	$ 1.5					

Significant Unobservable Inputs
December 31, 2018

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 99.4	Discounted Cash Flow	Forward Market Price	$ 26.29	$ 62.74	$ 42.50

Significant Unobservable Inputs
December 31, 2017

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 132.4	Discounted Cash Flow	Forward Market Price	$ 30.52	$ 170.43	$ 44.62

Significant Unobservable Inputs
December 31, 2018

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 10.8	$ 1.3	Discounted Cash Flow	Forward Market Price	$ (11.68)	$ 10.30	$ (1.40)

Significant Unobservable Inputs
December 31, 2017

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	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)

Significant Unobservable Inputs
December 31, 2018

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$ —	$ 2.5	Discounted Cash Flow	Forward Market Price (b)	$ 2.18	$ 3.54	$ 2.47
FTRs	5.6	0.8	Discounted Cash Flow	Forward Market Price (a)	(11.68)	10.30	(1.40)
Total	$ 5.6	$ 3.3					

Significant Unobservable Inputs
December 31, 2017

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$ —	$ 0.2	Discounted Cash Flow	Forward Market Price (b)	$ 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 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 December 31, 2018 and 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)

12. INCOME TAXES

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

Federal Tax Reform and Legislation

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, AEP recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, AEP continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and AEP will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

Federal Legislation

The IRS has proposed new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. Generally, AEP's regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in service after January 1, 2018 and AEP's competitive businesses will be eligible for 100% expensing. However, for self-constructed property and other property placed in service in 2018 for which construction began prior to January 1, 2018, taxpayers are required to evaluate the contractual terms to determine if these additions qualify for 100% expensing under Tax Reform or 50% bonus depreciation as provided under prior tax law.

During the fourth quarter of 2018, the IRS proposed new regulations that reflect changes as a result of Tax Reform concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide a de minimis test under which all interest is deductible if less than 10% is allocable to the competitive businesses. Management continues to review and evaluate the proposed regulations and at this time expect to be able to deduct materially all business interest expense under this de minimis provision.

Section 162(m) of the Internal Revenue Code generally limits the amount of compensation a company can deduct annually to $1 million for certain executive officers. The exemption from Section 162(m)'s deduction limit for performance-based compensation was repealed by Tax Reform, effective for taxable years ending after December 31, 2017. Management continues to evaluate whether any of its compensation plans qualify for transitional relief, such that payments made pursuant to these plans might be deductible.

Status of Tax Reform Regulatory Proceedings

For AEP's various regulatory jurisdictions where the regulatory effects of Tax Reform proceedings have not been fully resolved, the table below summarizes the current status. See Note 4 - Rate Matters for additional information.

Registrant (Jurisdiction)	Change in Tax Rate	Excess ADIT Subject to Normalization Requirements	Excess ADIT Not Subject to Normalization Requirements
AEP Texas (Texas-Distribution)	Order Issued	Order Issued	Order Issued – Partial (a)
AEP Texas (Texas-Transmission)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
APCo (Virginia)	Legislation Enacted – Case Pending (b)	Legislation Enacted – Case Pending (b)	Order Issued – Partial; Separate Case Pending (c)
I&M (Michigan)	Order Issued	Case Pending	Case Pending
SWEPCo (Louisiana)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)
SWEPCo (Texas)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
PJM FERC Transmission	Settlement Approved (e)	Settlement Approved (e)	Settlement Approved (e)
SPP FERC Transmission	To be addressed in a later filing	To be addressed in a later filing	To be addressed in a later filing

(a) A portion of the Excess ADIT that is not subject to rate normalization requirements is to be addressed in a later filing.
(b) Legislation has been issued for a blanket amount that is subject to true-up and final commission approval.
(c) In October 2018, the Virginia SCC issued an order approving APCo's request to refund a portion of the Excess ADIT that is not subject to rate normalization requirements to customers. The remainder is to be addressed in a separate pending case.
(d) Rates have been implemented through a filed formula rate plan that is subject to true-up and final commission approval.
(e) An ALJ has approved a settlement. The settlement is subject to final FERC ruling.

Income Tax Expense (Benefit)

The details of the Registrants' Income Tax Expense (Benefit) before discontinued operations as reported are as follows:

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (31.7)	$ 37.0	$ (14.2)	$ (31.9)	$ 60.9	$ 55.6	$ 35.6	$ 18.3
Deferred	112.8	(16.4)	82.3	(24.6)	(44.1)	(36.9)	(34.7)	(0.5)
Deferred Investment Tax Credits	9.2	(1.5)	—	0.1	(4.7)	—	(2.0)	(1.4)
Total Federal	90.3	19.1	68.1	(56.4)	12.1	18.7	(1.1)	16.4
State and Local:								
Current	30.8	1.8	(0.6)	3.7	15.8	4.6	(0.2)	2.3
Deferred	(8.5)	(0.1)	16.6	7.8	1.2	0.7	3.6	1.7
Deferred Investment Tax Credits	2.7	—	—	—	—	—	2.7	—
Total State and Local	25.0	1.7	16.0	11.5	17.0	5.3	6.1	4.0
Income Tax Expense (Benefit) Before Discontinued Operations	$ 115.3	$ 20.8	$ 84.1	$ (44.9)	$ 29.1	$ 24.0	$ 5.0	$ 20.4

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo (a)	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (4.0)	$ (85.7)	$ (130.4)	$ 15.3	$ (106.5)	$ 11.2	$ (77.1)	$ (30.1)
Deferred	856.6	63.3	254.8	166.9	202.1	141.3	122.7	84.8
Deferred Investment Tax Credits	48.6	(1.6)	—	(0.1)	(4.7)	—	(1.6)	(1.4)
Total Federal	901.2	(24.0)	124.4	182.1	90.9	152.5	44.0	53.3
State and Local:								
Current	16.0	0.6	1.1	(1.4)	(8.1)	0.2	(0.2)	(0.9)
Deferred	44.9	—	16.7	4.6	(1.4)	6.6	2.0	(4.3)
Deferred Investment Tax Credits	7.6	—	—	—	—	—	4.3	—
Total State and Local	68.5	0.6	17.8	3.2	(9.5)	6.8	6.1	(5.2)
Income Tax Expense (Benefit) Before Discontinued Operations	$ 969.7	$ (23.4)	$ 142.2	$ 185.3	$ 81.4	$ 159.3	$ 50.1	$ 48.1

Year Ended December 31, 2016	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (30.7)	$ 40.9	$ (129.4)	$ 64.1	$ (44.8)	$ 178.8	$ (28.0)	$ (96.7)
Deferred	(28.8)	29.9	205.9	125.8	104.9	(40.8)	77.2	172.6
Deferred Investment Tax Credits	17.6	(1.7)	—	(0.1)	3.8	—	(1.4)	(1.2)
Total Federal	(41.9)	69.1	76.5	189.8	63.9	138.0	47.8	74.7
State and Local:								
Current	(10.5)	(8.8)	0.4	4.4	3.4	4.2	(1.9)	(12.6)
Deferred	(21.2)	(0.4)	17.2	4.9	0.2	1.6	5.3	(10.0)
Deferred Investment Tax Credits	(0.1)	—	—	—	—	—	3.2	—
Total State and Local	(31.8)	(9.2)	17.6	9.3	3.6	5.8	6.6	(22.6)
Income Tax Expense (Benefit) Before Discontinued Operations	$ (73.7)	$ 59.9	$ 94.1	$ 199.1	$ 67.5	$ 143.8	$ 54.4	$ 52.1

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

AEP	Years Ended December 31, 2018	2017	2016
		(in millions)	
Net Income	$ 1,931.3	$ 1,928.9	$ 618.0
Less: Equity Earnings – Dolet Hills	(2.7)	—	—
Discontinued Operations (Net of Income Tax of $0, $0 and $0 in 2018, 2017 and 2016, Respectively)	—	—	2.5
Income Tax Expense (Benefit) Before Discontinued Operations	115.3	969.7	(73.7)
Pretax Income	$ 2,043.9	$ 2,898.6	$ 546.8
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 429.2	$ 1,014.5	$ 191.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	24.4	60.2	41.7
Investment Tax Credit Amortization	(20.2)	(18.8)	(12.3)
State and Local Income Taxes, Net	19.7	54.7	(20.7)
Removal Costs	(19.8)	(32.7)	(39.8)
AFUDC	(29.4)	(37.4)	(44.8)
Valuation Allowance	—	(1.8)	(128.3)
U.K. Windfall Tax	—	—	(12.9)
Tax Reform Adjustments	(10.9)	(26.7)	—
Tax Adjustments	—	(35.8)	(43.9)
Tax Reform Excess ADIT Reversal	(257.2)	—	—
Other	(20.5)	(6.5)	(4.1)
Income Tax Expense (Benefit) Before Discontinued Operations	$ 115.3	$ 969.7	$ (73.7)
Effective Income Tax Rate	5.6 %	33.5 %	(13.5)%

AEP Texas	Years Ended December 31, 2018	2017	2016
		(in millions)	
Net Income	$ 211.3	$ 310.5	$ 146.6
Discontinued Operations (Net of Income Tax of $0, $0 and $27.6 in 2018, 2017 and 2016, Respectively)	—	—	48.8
Income Tax Expense (Benefit)	20.8	(23.4)	59.9
Pretax Income	$ 232.1	$ 287.1	$ 255.3
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 48.7	$ 100.5	$ 89.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
State and Local Income Taxes, Net	1.3	0.4	(6.0)
AFUDC	(4.2)	(3.9)	(3.2)
Parent Company Loss Benefit	(3.1)	—	(2.5)
Tax Reform Adjustments	(11.0)	(117.4)	—
Tax Adjustments	—	(4.2)	(4.9)
U.K. Windfall Tax	—	—	(12.9)
Tax Reform Excess ADIT Reversal	(11.8)	—	—
Other	0.9	1.2	—
Income Tax Expense (Benefit) Before Discontinued Operations	$ 20.8	$ (23.4)	$ 59.9
Effective Income Tax Rate	9.0 %	(8.2)%	23.5 %

AEPTCo

	Years Ended December 31, 2018	2017 (a)	2016
		(in millions)	
Net Income	$ 315.9	$ 270.7	$ 192.7
Income Tax Expense	84.1	142.2	94.1
Pretax Income	$ 400.0	$ 412.9	$ 286.8
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 84.0	$ 144.5	$ 100.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
AFUDC	(14.1)	(17.0)	(18.3)
State and Local Income Taxes, Net	12.6	13.1	11.4
Tax Reform Adjustments	—	0.6	—
Other	1.6	1.0	0.6
Income Tax Expense	$ 84.1	$ 142.2	$ 94.1
Effective Income Tax Rate	21.0 %	34.4 %	32.8 %

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

APCo

	Years Ended December 31, 2018	2017	2016
		(in millions)	
Net Income	$ 367.8	$ 331.3	$ 369.1
Income Tax Expense (Benefit)	(44.9)	185.3	199.1
Pretax Income	$ 322.9	$ 516.6	$ 568.2
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 67.8	$ 180.8	$ 198.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	8.5	18.0	19.3
State and Local Income Taxes, Net	9.1	3.5	6.0
Removal Costs	(9.6)	(12.4)	(12.0)
AFUDC	(4.3)	(5.0)	(6.1)
Tax Reform Adjustments	0.1	4.3	—
Tax Reform Excess ADIT Reversal	(108.5)	—	—
Other	(8.0)	(3.9)	(7.0)
Income Tax Expense (Benefit)	$ (44.9)	$ 185.3	$ 199.1
Effective Income Tax Rate	(13.9)%	35.9 %	35.0 %

I&M

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Net Income	$ 261.3	$ 186.7	$ 239.9
Income Tax Expense	29.1	81.4	67.5
Pretax Income	$ 290.4	$ 268.1	$ 307.4
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 61.0	$ 93.8	$ 107.6
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	(0.7)	11.4	6.7
Investment Tax Credit Amortization	(4.7)	(4.7)	(4.7)
State and Local Income Taxes, Net	13.4	(1.0)	2.4
Removal Costs	(8.0)	(13.3)	(21.3)
AFUDC	(2.5)	(5.6)	(7.3)
Tax Adjustments	—	2.7	(14.2)
Tax Reform Adjustments	—	(2.9)	—
Tax Reform Excess ADIT Reversal	(25.8)	—	—
Other	(3.6)	1.0	(1.7)
Income Tax Expense	$ 29.1	$ 81.4	$ 67.5
Effective Income Tax Rate	10.0 %	30.4 %	22.0 %

OPCo

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Net Income	$ 325.5	$ 323.9	$ 282.2
Income Tax Expense	24.0	159.3	143.8
Pretax Income	$ 349.5	$ 483.2	$ 426.0
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 73.4	$ 169.1	$ 149.1
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	2.6	7.6	7.1
State and Local Income Taxes, Net	4.2	4.4	3.8
Tax Reform Adjustments	—	(14.4)	—
Tax Reform Excess ADIT Reversal	(51.0)	—	—
Parent Company Loss Benefit	(5.5)	(0.2)	(7.2)
Other	0.3	(7.2)	(9.0)
Income Tax Expense	$ 24.0	$ 159.3	$ 143.8
Effective Income Tax Rate	6.9 %	33.0 %	33.8 %

PSO

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Net Income	$ 83.2	$ 72.0	$ 100.0
Income Tax Expense	5.0	50.1	54.4
Pretax Income	$ 88.2	$ 122.1	$ 154.4
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 18.5	$ 42.7	$ 54.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.0	0.3	0.8
Investment Tax Credit Amortization	(1.7)	(1.6)	(1.4)
Parent Company Loss Benefit	(1.4)	—	—
State and Local Income Taxes, Net	4.8	4.0	4.2
Tax Reform Adjustments	—	2.8	—
Tax Reform Excess ADIT Reversal	(15.5)	—	—
Other	(0.7)	1.9	(3.2)
Income Tax Expense	$ 5.0	$ 50.1	$ 54.4
Effective Income Tax Rate	5.7 %	41.0 %	35.2 %

SWEPCo

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Net Income	$ 152.2	$ 137.5	$ 169.7
Less: Equity Earnings – Dolet Hills	(2.7)	—	—
Income Tax Expense	20.4	48.1	52.1
Pretax Income	$ 169.9	$ 185.6	$ 221.8
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 35.7	$ 65.0	$ 77.6
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	3.4	1.9	3.2
Depletion	(3.2)	(5.7)	(5.5)
State and Local Income Taxes, Net	3.2	(2.3)	(14.7)
AFUDC	(1.3)	(0.9)	(3.9)
Tax Adjustments	—	(9.9)	(0.9)
Tax Reform Adjustments	—	(0.4)	—
Tax Reform Excess ADIT Reversal	(16.0)	—	—
Other	(1.4)	0.4	(3.7)
Income Tax Expense	$ 20.4	$ 48.1	$ 52.1
Effective Income Tax Rate	12.0 %	25.9 %	23.5 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

AEP	December 31, 2018	2017
	(in millions)	
Deferred Tax Assets	$ 2,750.8	$ 3,504.6
Deferred Tax Liabilities	(9,837.3)	(10,318.5)
Net Deferred Tax Liabilities	$ (7,086.5)	$ (6,813.9)
Property Related Temporary Differences	$ (6,224.8)	$ (5,680.6)
Amounts Due to Customers for Future Federal Income Taxes	1,117.1	1,064.8
Deferred State Income Taxes (a)	(859.9)	(1,124.4)
Securitized Assets	(186.6)	(257.7)
Regulatory Assets	(454.1)	(500.3)
Deferred Income Taxes on Other Comprehensive Loss	32.0	25.7
Accrued Nuclear Decommissioning	(453.7)	(457.0)
Net Operating Loss Carryforward	78.3	86.6
Tax Credit Carryforward	113.7	174.7
Investment in Partnership	(300.5)	(222.0)
All Other, Net	52.0	76.3
Net Deferred Tax Liabilities	$ (7,086.5)	$ (6,813.9)

(a) In 2018, AEP recorded a $233 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

AEP Texas	December 31, 2018	2017
	(in millions)	
Deferred Tax Assets	$ 208.1	$ 221.0
Deferred Tax Liabilities	(1,121.2)	(1,134.1)
Net Deferred Tax Liabilities	$ (913.1)	$ (913.1)
Property Related Temporary Differences	$ (836.3)	$ (791.5)
Amounts Due to Customers for Future Federal Income Taxes	140.6	140.9
Deferred State Income Taxes	(27.1)	(27.5)
Regulatory Assets	(53.9)	(36.4)
Securitized Transition Assets	(134.7)	(190.5)
Deferred Income Taxes on Other Comprehensive Loss	4.0	4.1
Deferred Revenues	4.6	10.9
All Other, Net	(10.3)	(23.1)
Net Deferred Tax Liabilities	$ (913.1)	$ (913.1)

AEPTCo

	December 31,	
	2018	2017 (a)
	(in millions)	
Deferred Tax Assets	$ 142.9	$ 163.0
Deferred Tax Liabilities	(847.3)	(763.4)
Net Deferred Tax Liabilities	$ (704.4)	$ (600.4)
Property Related Temporary Differences	$ (755.0)	$ (653.4)
Amounts Due to Customers for Future Federal Income Taxes	101.6	89.7
Deferred State Income Taxes (b)	(51.9)	(77.4)
Deferred Federal Income Taxes on Deferred State Income Taxes	—	16.3
Net Operating Loss Carryforward	13.4	16.8
Tax Credit Carryforward	—	0.3
All Other, Net	(12.5)	7.3
Net Deferred Tax Liabilities	$ (704.4)	$ (600.4)

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

(b) In 2018, AEPTCo recorded a $21 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

APCo

	December 31,	
	2018	2017
	(in millions)	
Deferred Tax Assets	$ 475.2	$ 614.4
Deferred Tax Liabilities	(2,101.0)	(2,180.1)
Net Deferred Tax Liabilities	$ (1,625.8)	$ (1,565.7)
Property Related Temporary Differences	$ (1,393.6)	$ (1,308.2)
Amounts Due to Customers for Future Federal Income Taxes	224.2	228.0
Deferred State Income Taxes (a)	(280.3)	(335.7)
Regulatory Assets	(73.8)	(83.9)
Securitized Assets	(54.3)	(59.3)
Deferred Income Taxes on Other Comprehensive Loss	1.3	(0.4)
Tax Credit Carryforward	0.2	16.6
All Other, Net	(49.5)	(22.8)
Net Deferred Tax Liabilities	$ (1,625.8)	$ (1,565.7)

(a) In 2018, APCo recorded a $51 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

I&M

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 771.6	$ 1,096.4
Deferred Tax Liabilities	(1,719.6)	(2,050.2)
Net Deferred Tax Liabilities	$ (948.0)	$ (953.8)
Property Related Temporary Differences	$ (445.0)	$ (403.0)
Amounts Due to Customers for Future Federal Income Taxes	142.0	137.6
Deferred State Income Taxes (a)	(139.7)	(180.6)
Deferred Income Taxes on Other Comprehensive Loss	3.7	3.9
Accrued Nuclear Decommissioning	(453.7)	(457.0)
Regulatory Assets	(31.9)	(43.8)
Net Operating Loss Carryforward	0.2	1.6
All Other, Net	(23.6)	(12.5)
Net Deferred Tax Liabilities	$ (948.0)	$ (953.8)

(a) In 2018, I&M recorded a $48 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

OPCo

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 209.0	$ 286.0
Deferred Tax Liabilities	(972.3)	(1,048.9)
Net Deferred Tax Liabilities	$ (763.3)	$ (762.9)
Property Related Temporary Differences	$ (826.9)	$ (761.2)
Amounts Due to Customers for Future Federal Income Taxes	130.9	127.3
Deferred State Income Taxes	(26.8)	(41.7)
Regulatory Assets	(55.0)	(107.7)
Deferred Income Taxes on Other Comprehensive Loss	(0.3)	(0.6)
Deferred Fuel and Purchased Power	(1.6)	(24.5)
All Other, Net	16.4	45.5
Net Deferred Tax Liabilities	$ (763.3)	$ (762.9)

PSO	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 229.6	$ 269.2
Deferred Tax Liabilities	(837.4)	(911.2)
Net Deferred Tax Liabilities	$ (607.8)	$ (642.0)
Property Related Temporary Differences	$ (609.4)	$ (623.8)
Amounts Due to Customers for Future Federal Income Taxes	107.1	111.6
Deferred State Income Taxes (a)	(103.8)	(142.7)
Regulatory Assets	(32.3)	(34.4)
Deferred Income Taxes on Other Comprehensive Loss	(0.6)	(0.8)
Deferred Federal Income Taxes on Deferred State Income Taxes	—	33.5
Net Operating Loss Carryforward	16.4	23.1
Tax Credit Carryforward	—	0.7
All Other, Net	14.8	(9.2)
Net Deferred Tax Liabilities	$ (607.8)	$ (642.0)

(a) In 2018, PSO recorded a $33 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

SWEPCo	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 317.4	$ 349.4
Deferred Tax Liabilities	(1,220.2)	(1,267.1)
Net Deferred Tax Liabilities	$ (902.8)	$ (917.7)
Property Related Temporary Differences	$ (929.1)	$ (908.8)
Amounts Due to Customers for Future Federal Income Taxes	145.8	135.8
Deferred State Income Taxes (a)	(156.0)	(189.2)
Regulatory Assets	(30.8)	(30.8)
Deferred Income Taxes on Other Comprehensive Loss	1.4	1.3
Capital/Impairment Loss - Turk Plant	15.8	17.4
Net Operating Loss Carryforward	36.2	38.7
Tax Credit Carryforward	—	0.8
All Other, Net	13.9	17.1
Net Deferred Tax Liabilities	$ (902.8)	$ (917.7)

(a) In 2018, SWEPCo recorded a $38 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective negative evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions.

AEP recorded changes in the valuation allowance in the second quarter of 2016 related to the reversal of a $56 million unrealized capital loss where AEP effectively settled a 2011 audit issue with the IRS. AEP also recorded changes in the third quarter of 2016 by reducing the capital loss valuation allowance by $66 million to reflect the impact of the reclassification of certain assets held for sale and the filing of the 2015 federal income tax return. The sale of these assets held for sale are expected to result in a gain, the character of which will allow AEP to recognize the capital loss and allowed AEP to reverse substantially all of the remaining capital loss valuation allowance previously recorded. During the fourth quarter of 2016, AEP reversed $6 million of the valuation allowance associated with charitable contributions that expired at the end of the year. As of December 31, 2016 there was a valuation allowance of $2 million recorded against AEP's deferred tax asset balance related to an unrealized capital loss carryforward.

Valuation allowance activity for the years ended December 31, 2018 and 2017 was immaterial.

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 Joint Committee approved the settlement in November 2018. The settlement did not materially impact the Registrants net income, cash flows or financial condition. The IRS examination of 2016 began in October 2018.

AEP and subsidiaries file income tax returns in various state and local 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 2007.

Net Income Tax Operating Loss Carryforward

As of December 31, 2018, AEP, AEPTCo, I&M, PSO and SWEPCo have state net income tax operating loss carryforwards as indicated in the table below:

Company	State/Municipality	State Net Income Tax Operating Loss Carryforward	Years of Expiration
		(in millions)	
AEP	Arkansas	$ 67.8	2018 - 2023
AEP	Kentucky	130.4	2025 - 2037
AEP	Louisiana	517.3	2030 - 2038
AEP	Oklahoma	644.2	2032 - 2037
AEP	Tennessee	28.6	2025 - 2033
AEP	Virginia	22.8	2030 - 2038
AEP	West Virginia	5.1	2029 - 2037
AEP	Ohio Municipal	226.5	2019 - 2023
AEPTCo	Oklahoma	264.0	2032 - 2037
AEPTCo	Ohio Municipal	43.6	2019 - 2023
I&M	West Virginia	3.8	2032 - 2037
PSO	Oklahoma	348.8	2034 - 2037
SWEPCo	Arkansas	67.1	2021 - 2023
SWEPCo	Louisiana	504.9	2032 - 2037

As of December 31, 2018, AEP and AEPTCo have recorded valuation allowances of $5 million and $1 million, respectively, against certain state and municipal net income tax operating loss carryforwards since future taxable income is not expected to be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires. Management anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires for each state.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2012, 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. As of December 31, 2018, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2037 through 2038.

Company	Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration	Total State Tax Credit Carryforward	State Tax Credit Carryforward Subject to Expiration
		(in millions)		
AEP	$ 113.7	$ 100.9	$ 34.2	$ —
APCo	0.2	—	—	—
I&M	0.9	—	—	—
PSO	—	—	34.2	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

The reconciliations of the beginning and ending amounts of unrecognized tax benefits are as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2018	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)
Increase – Tax Positions Taken During a Prior Period	0.1	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During a Prior Period	—	—	—	—	—	—	—	—
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(71.0)	—	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	(1.1)	—	—	—	—	—	—	—
Balance as of December 31, 2018	$ 14.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2017	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3
Increase – Tax Positions Taken During a Prior Period	4.5	2.0	—	—	0.2	—	0.1	1.7
Decrease – Tax Positions Taken During a Prior Period	(28.0)	(12.3)	—	—	(0.5)	—	(0.9)	(5.4)
Increase – Tax Positions Taken During the Current Year	3.4	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	7.9	3.0	—	—	(0.3)	—	0.7	1.6
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2017	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2016	$ 187.0	$ 27.8	$ —	$ 0.3	$ 2.4	$ 6.9	$ 1.3	$ 9.3
Increase – Tax Positions Taken During a Prior Period	86.0	6.5	—	—	1.8	—	0.1	1.3
Decrease – Tax Positions Taken During a Prior Period	(161.2)	(15.0)	—	(0.3)	(0.4)	—	(1.3)	(9.3)
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(13.0)	(12.8)	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2016	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant was as follows:

Company	2018	2017	2016
		(in millions)	
AEP	$ 11.6	$ 10.5	$ 15.8
AEP Texas	(0.7)	(0.5)	4.2
AEPTCo	—	—	—
APCo	—	—	—
I&M	2.6	2.1	2.5
OPCo	5.4	4.5	4.4
PSO	—	—	0.1
SWEPCo	(0.6)	(0.5)	0.8

State Tax Legislation

In March 2016, the Texas Comptroller of Public Accounts issued clarifying guidance regarding the treatment of transmission and distribution expenses included in the computation of taxable income for purposes of calculating the Texas income/franchise tax. The guidance clarified which specific transmission and distribution expenses are included in the computation of the cost of goods sold deduction. This guidance resulted in a net favorable adjustment to net income of $21 million, $7 million, $2 million and $9 million in 2016 for AEP, AEP Texas, PSO and SWEPCo, respectively.

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 Section 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.

In June 2018, the United States Supreme Court issued a decision which eliminated a physical presence requirement for the imposition of sales and use tax and instead applied an economic nexus concept. Although this case was specific to sales and use taxes, many states are beginning to consider whether they could also apply this economic nexus concept to income taxes. Management continues to monitor state legislation to determine whether it could create any income tax liability in any states in which AEP currently does not file.

13. LEASES

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

Leases of property, plant and equipment are for remaining periods up to 17 years and require payments of related property taxes, maintenance and operating costs. Many of the leases have purchase or renewal options. Leases not renewed are often replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 245.0	$ 13.6	$ 2.7	$ 18.2	$ 89.2	$ 10.7	$ 5.7	$ 6.5
Amortization of Capital Leases	62.4	4.8	0.1	7.0	6.6	3.9	3.2	11.2
Interest on Capital Leases	16.4	1.2	—	3.0	3.3	0.5	0.4	3.2
Total Lease Rental Costs	$ 323.8	$ 19.6	$ 2.8	$ 28.2	$ 99.1	$ 15.1	$ 9.3	$ 20.9

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 231.3	$ 10.5	$ 1.7	$ 17.5	$ 88.4	$ 8.2	$ 4.4	$ 5.3
Amortization of Capital Leases	66.3	4.0	—	6.9	11.1	4.1	4.0	11.2
Interest on Capital Leases	16.7	0.8	—	3.7	3.2	0.5	0.6	3.6
Total Lease Rental Costs	$ 314.3	$ 15.3	$ 1.7	$ 28.1	$ 102.7	$ 12.8	$ 9.0	$ 20.1

Year Ended December 31, 2016	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 224.9	$ 9.8 (a)	$ 0.9	$ 16.6	$ 90.5	$ 7.1	$ 5.0	$ 6.7
Amortization of Capital Leases	93.7	3.4	—	6.4	35.6	4.2	3.7	13.6
Interest on Capital Leases	18.9	0.6	—	3.5	3.7	0.5	0.6	5.1
Total Lease Rental Costs	$ 337.5	$ 13.8	$ 0.9	$ 26.5	$ 129.8	$ 11.8	$ 9.3	$ 25.4

(a) Amounts include lease expenses related to Desert Sky and Trent that were classified as Other Operation Expense from Discontinued Operations on the statements of income in the amount of $1 million for the year ended December 31, 2016. See Note 7 - Dispositions and Impairments for additional information.

The following tables show the property, plant and equipment under capital leases and related obligations recorded on the Registrants' balance sheets. Unless shown as a separate line on the balance sheets due to materiality, current capital lease obligations are included in Other Current Liabilities and long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the Registrants' balance sheets.

December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Capital Leases:								
Generation	$ 131.3	$ —	$ —	$ 38.7	$ 27.0	$ —	$ 2.6	$ 34.3
Other Property, Plant and Equipment	373.9	38.8	0.2	17.3	33.3	20.4	17.6	119.8
Total Property, Plant and Equipment	505.2	38.8	0.2	56.0	60.3	20.4	20.2	154.1
Accumulated Amortization	226.4	10.3	0.1	16.2	21.6	8.3	7.9	99.9
Net Property, Plant and Equipment Under Capital Leases	$ 278.8	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 54.2
Obligations Under Capital Leases:								
Noncurrent Liability	$ 233.5	$ 24.0	$ —	$ 33.7	$ 33.4	$ 9.2	$ 9.5	$ 50.6
Liability Due Within One Year	55.5	4.5	0.1	6.1	5.3	2.9	2.8	10.2
Total Obligations Under Capital Leases	$ 289.0	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Capital Leases:								
Generation	$ 141.7	$ —	$ —	$ 42.5	$ 27.2	$ —	$ 8.9	$ 33.4
Other Property, Plant and Equipment	373.3	32.7	0.2	18.0	34.0	22.8	18.0	122.4
Total Property, Plant and Equipment	515.0	32.7	0.2	60.5	61.2	22.8	26.9	155.8
Accumulated Amortization	229.0	10.0	—	19.0	21.1	10.6	15.3	94.0
Net Property, Plant and Equipment Under Capital Leases	$ 286.0	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.6	$ 61.8
Obligations Under Capital Leases:								
Noncurrent Liability	$ 238.8	$ 18.5	$ 0.1	$ 34.9	$ 34.3	$ 7.9	$ 8.3	$ 57.8
Liability Due Within One Year	59.0	4.2	0.1	6.6	5.8	4.3	3.5	11.2
Total Obligations Under Capital Leases	$ 297.8	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.8	$ 69.0

Future minimum lease payments consisted of the following as of December 31, 2018:

Capital Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2019	$ 70.8	$ 5.8	$ 0.1	$ 9.0	$ 8.2	$ 3.3	$ 3.4	$ 13.1
2020	60.2	5.3	—	8.0	7.2	2.7	2.6	11.5
2021	51.7	4.7	—	7.3	6.6	2.3	2.0	10.5
2022	43.8	4.2	—	6.8	6.1	1.7	1.6	9.4
2023	35.5	3.7	—	6.3	5.7	1.2	1.4	8.6
Later Years	90.2	10.1	—	13.3	21.7	2.8	3.3	18.7
Total Future Minimum Lease Payments	352.2	33.8	0.1	50.7	55.5	14.0	14.3	71.8
Less Estimated Interest Element	63.2	5.3	—	10.9	16.8	1.9	2.0	11.0
Estimated Present Value of Future Minimum Lease Payments	$ 289.0	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

Noncancelable Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2019	$ 259.6	$ 15.1	$ 2.3	$ 17.6	$ 92.6	$ 14.5	$ 6.5	$ 7.4
2020	250.1	14.1	1.8	16.5	89.3	13.2	6.0	7.2
2021	232.7	13.2	1.0	13.9	84.8	10.9	5.0	6.7
2022	222.5	12.2	0.5	12.8	83.8	10.0	4.6	6.1
2023	58.3	10.8	0.1	9.9	6.5	8.8	4.1	5.0
Later Years	165.2	28.4	—	20.5	19.5	31.7	10.7	11.7
Total Future Minimum Lease Payments	$1,188.4	$ 93.8	$ 5.7	$ 91.2	$ 376.5	$ 89.1	$ 36.9	$ 44.1

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 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 amount guaranteed. As of December 31, 2018, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss
	(in millions)
AEP	$ 47.7
AEP Texas	10.8
APCo	8.8
I&M	3.7
OPCo	7.9
PSO	3.8
SWEPCo	4.3

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2018 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2019	$ 147.8	$ 73.9
2020	147.8	73.9
2021	147.8	73.9
2022	147.2	73.6
Total Future Minimum Lease Payments	$ 590.6	$ 295.3

(a) AEP's future minimum lease payments include equal shares from AEGCo and I&M.

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

In 2003, AEP Transportation LLC, a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. In 2008, AEP Transportation LLC 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 exercised all renewal options for the maximum lease term. The future minimum lease obligations were $6 million and $7 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2018. These obligations are included in the future minimum lease payments schedule earlier in this note.

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 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 December 31, 2018, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. Certain 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 December 31, 2018, the maximum potential amount of future payments required under the guaranteed leases was $44 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 December 31, 2018, AEP's boat and barge lease guarantee liability was $5 million, of which $1 million was recorded in Other Current Liabilities and $4 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 rating 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.

14. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

The following table is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury	
Balance, December 31, 2015	511,389,173	20,336,592	
Issued	659,347	—	
Balance, December 31, 2016	512,048,520	20,336,592	
Issued	162,124	—	
Treasury Stock Reissued	—	(131,546)	(a)
Balance, December 31, 2017	512,210,644	20,205,046	
Issued	1,239,392	—	
Treasury Stock Reissued	—	(886)	(a)
Balance, December 31, 2018	513,450,036	20,204,160	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Share-based Compensation. See "Shared-based Compensation Plans" section of Note 15 for additional information.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2018	Interest Rate Ranges as of December 31, 2018	Interest Rate Ranges as of December 31, 2017	Outstanding as of December 31, 2018	Outstanding as of December 31, 2017
AEP					(in millions)	
Senior Unsecured Notes	2018-2048	4.36%	2.15%-8.13%	2.15%-8.13%	$ 18,903.3	$ 16,478.3
Pollution Control Bonds (a)	2018-2038 (b)	3.14%	1.60%-6.30%	1.54%-6.30%	1,643.8	1,621.7
Notes Payable – Nonaffiliated (c)	2019-2032	3.95%	3.20%-6.37%	2.03%-6.37%	204.7	260.8
Securitization Bonds	2018-2028 (d)	3.65%	1.98%-5.31%	1.98%-5.31%	1,111.4	1,416.5
Spent Nuclear Fuel Obligation (e)					273.6	268.6
Other Long-term Debt	2018-2059	3.72%	1.15%-13.718%	1.15%-13.718%	1,209.9	1,127.4
Total Long-term Debt Outstanding					$ 23,346.7	$ 21,173.3
AEP Texas						
Senior Unsecured Notes	2018-2047	4.06%	2.40%-6.76%	2.40%-6.76%	$ 2,398.4	$ 1,932.2
Pollution Control Bonds	2020-2030	4.39%	1.75%-6.30%	1.75%-6.30%	490.9	490.5
Securitization Bonds	2018-2024 (d)	3.95%	1.98%-5.31%	1.98%-5.31%	791.2	1,026.1
Other Long-term Debt	2019-2059	3.94%	3.94%-4.50%	2.75%-4.50%	200.8	200.5
Total Long-term Debt Outstanding					$ 3,881.3	$ 3,649.3
AEPTCo						
Senior Unsecured Notes	2018-2048	3.92%	2.68%-5.52%	2.68%-5.52%	$ 2,823.0	$ 2,550.4
Total Long-term Debt Outstanding					$ 2,823.0	$ 2,550.4
APCo						
Senior Unsecured Notes	2021-2045	5.20%	3.30%-7.00%	3.30%-7.00%	$ 3,047.3	$ 3,045.1
Pollution Control Bonds (a)	2018-2038 (b)	2.64%	1.70%-5.38%	1.625%-5.38%	616.0	512.2
Securitization Bonds	2023-2028 (d)	3.06%	2.008%-3.772%	2.008%-3.772%	272.3	295.9
Other Long-term Debt	2019-2026	3.91%	3.74%-13.718%	2.73%-13.718%	127.0	126.9
Total Long-term Debt Outstanding					$ 4,062.6	$ 3,980.1
I&M						
Senior Unsecured Notes	2019-2048	4.38%	3.20%-6.05%	3.20%-7.00%	$ 2,149.0	$ 1,809.0
Pollution Control Bonds (a)	2018-2025 (b)	2.49%	1.81%-3.05%	1.75%-2.75%	264.5	264.6
Notes Payable – Nonaffiliated (c)	2019-2022	3.30%	3.20%-3.38%	2.03%-2.19%	135.8	188.6
Spent Nuclear Fuel Obligation (e)					273.6	268.6
Other Long-term Debt	2018-2025	3.80%	3.66%-6.00%	2.82%-6.00%	212.5	214.3
Total Long-term Debt Outstanding					$ 3,035.4	$ 2,745.1
OPCo						
Senior Unsecured Notes	2018-2048	5.52%	4.15%-6.60%	5.375%-6.60%	$ 1,635.5	$ 1,591.4
Pollution Control Bonds	2038	5.80%	5.80%	5.80%	32.3	32.3
Securitization Bonds	2019 (d)	2.049%	2.049%	2.049%	47.8	94.5
Other Long-term Debt	2028	1.15%	1.15%	1.15%	1.0	1.1
Total Long-term Debt Outstanding					$ 1,716.6	$ 1,719.3
PSO						
Senior Unsecured Notes	2019-2046	4.80%	3.05%-6.625%	3.05%-6.625%	$ 1,144.9	$ 1,144.1
Pollution Control Bonds	2020	4.45%	4.45%	4.45%	12.6	12.6
Other Long-term Debt	2019-2027	3.70%	3.00%-3.72%	2.584%-3.00%	129.5	129.8
Total Long-term Debt Outstanding					$ 1,287.0	$ 1,286.5
SWEPCo						
Senior Unsecured Notes	2018-2048	4.04%	2.75%-6.20%	2.75%-6.45%	$ 2,427.0	$ 2,110.7
Pollution Control Bonds	2018-2019	1.60%	1.60%	1.60%-4.95%	53.5	135.1
Notes Payable – Nonaffiliated (c)	2024-2032	5.23%	4.58%-6.37%	4.58%-6.37%	68.9	72.1
Other Long-term Debt	2020-2028	4.03%	3.75%-4.68%	2.925%-4.28%	164.0	124.0
Total Long-term Debt Outstanding					$ 2,713.4	$ 2,441.9

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.
(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.
(e) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See “Spent Nuclear Fuel Disposal” section of Note 6 for additional information.

As of December 31, 2018, outstanding long-term debt was payable as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2019	$ 1,698.5	$ 501.1	$ 85.0	$ 430.7	$ 155.4	$ 47.9	$ 375.5	$ 59.7
2020	1,508.3	377.7	—	90.3	41.6	0.1	13.2	121.2
2021	1,961.5	66.2	50.0	393.0	256.4	500.1	250.5	6.2
2022	1,668.4	493.0	104.0	230.4	7.0	0.1	0.5	281.2
2023	539.6	195.0	60.0	26.6	252.4	0.1	0.5	6.2
After 2023	16,150.9	2,275.5	2,551.0	2,924.4	2,351.5	1,182.8	652.0	2,262.9
Principal Amount	23,527.2	3,908.5	2,850.0	4,095.4	3,064.3	1,731.1	1,292.2	2,737.4
Unamortized Discount, Net and Debt Issuance Costs	(180.5)	(27.2)	(27.0)	(32.8)	(28.9)	(14.5)	(5.2)	(24.0)
Total Long-term Debt Outstanding	$ 23,346.7	$ 3,881.3	$ 2,823.0	$ 4,062.6	$ 3,035.4	$ 1,716.6	$ 1,287.0	$ 2,713.4

As of December 31, 2018, trustees held, on behalf of AEP, $574 million of their reacquired Pollution Control Bonds. Of this total, $345 million related to OPCo.

Long-term Debt Subsequent Events

In January and February 2019, I&M retired $15 million and $2 million, respectively, of Notes Payable related to DCC Fuel.

In January and February 2019, Transource Energy issued $3 million and $3 million, respectively, of variable rate Other Long-term Debt due in 2020.

In January 2019, AEP Texas retired $104 million of Securitization Bonds.

In January 2019, OPCo retired $23 million of Securitization Bonds.

In January 2019, SWEPCo retired $54 million of 1.60% Pollution Control Bonds due in 2019.

In February 2019, APCo retired $12 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 0.6% of consolidated tangible net assets as of December 31,2018. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreement.

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. However, the Federal Power Act creates a reserve on retained 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 most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2018, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $12.4 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2018, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 1,591.4 (a)	$ 353.7	$ —	$ 17.6	$ 454.1	$ —	$ 152.7	$ 526.4

(a) Includes the restrictions of consolidated and non-consolidated subsidiaries.

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. As of December 31, 2018, AEP had $7.7 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.3 billion, $1.2 billion and $1.1 billion of dividends to common shareholders for the years ended December 31, 2018, 2017 and 2016, respectively.

Lines of Credit and Short-term Debt (Applies to AEP and SWEPCo)

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. As of December 31, 2018, AEP had a $4 billion revolving credit facility to support its commercial paper program. The commercial paper program for the year ended 2018, had a weighted-average interest rate of 2.33% and a maximum amount outstanding of $2.3 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2018		2017	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in millions)		**(in millions)**	
AEP	Securitized Debt for Receivables (b)	$ 750.0	2.16%	$ 718.0	1.22%
AEP	Commercial Paper	1,160.0	2.96%	898.6	1.85%
SWEPCo	Notes Payable	—	—%	22.0	2.92%
	Total Short-term Debt	$ 1,910.0		$ 1,638.6	

(a) Weighted-average interest rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

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 December 31, 2018 and 2017 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2018:

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 December 31, 2018	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 390.6	$ 106.9	$ 176.0	$ 47.1	$ (216.0)	$ 500.0	
AEPTCo	371.3	276.4	177.9	58.4	35.8	795.0	(a)
APCo	295.5	23.7	175.3	23.3	(182.6)	600.0	
I&M	322.1	657.8	255.5	110.7	11.6	500.0	
OPCo	270.8	225.0	167.8	189.4	(114.1)	500.0	
PSO	193.7	31.8	104.5	12.9	(105.5)	300.0	
SWEPCo	200.1	533.7	143.2	268.1	81.4	350.0	

Year Ended December 31, 2017:

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 December 31, 2017	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 296.0	$ 451.7	$ 194.8	$ 264.6	$ 103.5	$ 400.0	
AEPTCo	467.2	268.0	180.5	119.8	109.2	795.0	(a)
APCo	231.5	160.7	144.3	30.0	(162.5)	600.0	
I&M	367.4	12.6	204.9	12.6	(199.2)	500.0	
OPCo	280.6	56.2	137.0	27.9	(87.8)	400.0	
PSO	185.2	—	119.3	—	(149.6)	300.0	
SWEPCo	187.5	178.6	95.5	169.5	(118.7)	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 tables 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, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2018 and 2017 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2018:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2018
		(in millions)	
AEP Texas	$ 8.4	$ 8.1	$ 8.0
SWEPCo	2.0	2.0	2.0

Year Ended December 31, 2017:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2017
		(in millions)	
AEP Texas	$ 8.6	$ 8.3	$ 8.4
SWEPCo	2.0	2.0	2.0

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. In January 2017, management removed AEP Texas from the direct financing relationship with AEP to better reflect current business operations. The amounts of outstanding loans to and borrowings from AEP as of December 31, 2018 and 2017 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo' balance sheets. AEPTCo's direct financing activities with AEP are described in the following tables:

Year Ended December 31, 2018:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings From AEP as of December 31, 2018	Loans to AEP as of December 31, 2018	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 1.2	$ 104.7	$ 1.1	$ 49.8	$ 1.2	$ 16.9	$ 75.0	(a)

Year Ended December 31, 2017:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2017	Loans to AEP as of December 31, 2017	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 4.1	$ 151.9	$ 1.1	$ 39.3	$ 1.1	$ 22.5	$ 75.0	(a)

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

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Years Ended December 31,		
	2018	2017	2016
Maximum Interest Rate	2.97%	1.85%	1.02%
Minimum Interest Rate	1.81%	0.92%	0.69%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for the Years Ended December 31,		
Company	2018	2017	2016	2018	2017	2016
AEP Texas	2.26%	1.29%	0.88%	2.29%	1.26%	0.72%
AEPTCo	2.27%	1.36%	0.85%	2.10%	1.27%	0.83%
APCo	2.26%	1.28%	0.80%	2.21%	1.29%	0.82%
I&M	2.16%	1.27%	0.80%	2.08%	1.29%	0.80%
OPCo	2.18%	1.37%	0.85%	2.47%	0.98%	0.74%
PSO	2.27%	1.32%	0.96%	1.98%	—%	0.83%
SWEPCo	2.31%	1.28%	0.79%	2.00%	0.98%	0.90%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool are summarized in the following tables:

Year Ended December 31, 2018:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from 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 Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	—%	—%	2.97%	1.83%	—%	2.36%
SWEPCo	—%	—%	2.97%	1.83%	—%	2.36%

Year Ended December 31, 2017:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from 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 Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	—%	—%	1.85%	—%	—%	1.32%
SWEPCo	—%	—%	1.85%	—%	—%	1.32%

Year Ended December 31, 2016:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from 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 Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	1.11%	0.97%	1.02%	0.75%	1.00%	0.86%
SWEPCo	—%	—%	1.02%	0.69%	—%	0.82%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following tables:

Year Ended December 31, 2018:

Company	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
AEP Texas	—%	—%	—%	—%	—%	—%
AEPTCo	2.97%	1.76%	2.97%	1.76%	2.36%	2.36%

Year Ended December 31, 2017:

Company	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
AEP Texas	—%	—%	—%	—%	—%	—%
AEPTCo	1.85%	0.92%	1.85%	0.92%	1.33%	1.36%

Year Ended December 31, 2016:

Company	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
AEP Texas	0.98%	0.69%	1.02%	0.99%	0.83%	1.00%
AEPTCo	1.02%	0.69%	1.02%	0.69%	0.83%	0.87%

Interest expense and interest income related to the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense and Interest Income, respectively, on each of the Registrant Subsidiaries' statements of income. The interest expense and interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2018, 2017 and 2016.

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

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 includes a $125 million and a $625 million facility which expire in July 2020 and 2021, respectively.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31, 2018	2017	2016
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	2.16%	1.22%	0.70%
Net Uncollectible Accounts Receivable Written Off	$ 27.6	$ 23.4	$ 23.7

	December 31, 2018	2017
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 972.5	$ 925.5
Short-term – Securitized Debt of Receivables	750.0	718.0
Delinquent Securitized Accounts Receivable	50.3	41.1
Bad Debt Reserves Related to Securitization	27.5	28.7
Unbilled Receivables Related to Securitization	281.4	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 AEPTCo and AEP Texas)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were:

Company	December 31, 2018	2017
	(in millions)	
APCo	$ 133.3	$ 136.2
I&M	152.9	136.5
OPCo	395.2	367.4
PSO	109.7	115.1
SWEPCo	150.3	138.2

The fees paid to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
APCo	$ 7.0	$ 5.6	$ 6.7
I&M	9.2	6.7	7.1
OPCo	26.3	21.7	28.9
PSO	7.9	7.0	6.2
SWEPCo	8.9	7.2	6.9

The proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
APCo	$ 1,421.0	$ 1,372.8	$ 1,412.5
I&M	1,843.0	1,612.9	1,596.2
OPCo	2,674.5	2,339.0	2,633.0
PSO	1,484.6	1,337.0	1,269.3
SWEPCo	1,736.1	1,563.4	1,531.7

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

Awards under AEP's long-term incentive plan may be granted to employees and directors. The Amended and Restated American Electric Power System Long-Term Incentive Plan (the "Prior Plan"), was replaced prospectively for new grants by the American Electric Power System 2015 Long-Term Incentive Plan (the "2015 LTIP") effective in April 2015. The 2015 LTIP was subsequently amended in September 2016. The 2015 LTIP provides for a maximum of 10 million common shares to be available for grant to eligible employees and directors. As of December 31, 2018, 8,194,046 shares remained available for issuance under the 2015 LTIP. No new awards may be granted under the Prior Plan. The 2015 LTIP awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance share units, cash-based awards and other stock-based awards. If a share is issued pursuant to a stock option or a stock appreciation right, it will reduce the aggregate amount authorized under the 2015 LTIP by 0.286 of a share. If a share is issued for any other award that settles in AEP stock, it will reduce the aggregate amount authorized under the 2015 LTIP by one share. Cash settled awards do not reduce the aggregate amount authorized under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Units

Performance units granted prior to 2017 are settled in cash rather than AEP common stock and do not reduce the aggregate share authorization. These performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. Performance units granted from 2017 on will be settled in AEP common stock and will reduce the aggregate share authorization. In all cases the number of performance units held at the end of the three-year performance period is multiplied by the performance score for such period to determine the actual number of performance units that participants realize. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy stock ownership requirements. If those employees have not met their stock ownership requirements, a portion or all of their performance units are mandatorily deferred as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance units and AEP career shares accrue as additional units. Management records compensation cost for performance units over an approximately three-year vesting period. The liability for the pre 2017 performance units is recorded in Employee Benefits and Pension Obligations on the balance sheets and is adjusted for changes in value. Performance units settled in shares are recorded as mezzanine equity on the balance sheets and compensation cost is calculated at fair value using two metrics. Half is based on the total shareholder return measure, which is determined based on a third party Monte Carlo valuation. That metric does not change over the three-year vesting period. The other half is based on a three-year cumulative earnings per share metric which is adjusted quarterly for changes in performance relative to a target approved by the HR Committee.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP career shares for the years ended December 31, 2018, 2017 and 2016 as follows:

Performance Units	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands) (a)	581.4	590.7	597.4
Weighted Average Unit Fair Value at Grant Date	$ 67.21	$ 69.78	$ 62.77
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands) (b)	80.2	74.6	89.2
Weighted Average Fair Value at Grant Date	$ 70.58	$ 72.35	$ 63.83
Vesting Period (in years)	(c)	(c)	(c)

(a) Awarded units in 2018 and 2017 were mezzanine equity awards and awarded units in 2016 were liability awards.
(b) Awarded dividends in 2018 and 2017 were a mix of equity awards and liability awards, and all awarded dividends in 2016 were liability awards.
(c) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.

Performance scores and final awards are determined and approved by the HR Committee in accordance with the pre-established performance measures within approximately one month after the end of the performance period. The performance scores for all performance periods were dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to a peer group of similar companies and (b) three-year cumulative earnings per share measured relative to a target approved by the HR Committee.

The certified performance scores and units earned for the three-year periods ended December 31, 2018, 2017 and 2016 were as follows:

Performance Units	Years Ended December 31, 2018	2017	2016
Certified Performance Score	136.7%	164.8%	163.9%
Performance Units Earned	820,780	956,055	1,111,966
Performance Units Mandatorily Deferred as AEP Career Shares	11,248	20,213	9,963
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	56,826	47,177	51,684
Performance Units to be Settled in Cash	752,706	888,665	1,050,319

The settlements for the years ended December 31, 2018, 2017 and 2016 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2018	2017	2016
		(in millions)	
Cash Settlements for Performance Units	$ 66.9	$ 64.9	$ 62.7
Cash Settlements for Career Share Distributions	—	—	9.1
AEP Common Stock Settlements for Career Share Distributions	5.1	0.4	—

A summary of the status of AEP's nonvested Performance Units as of December 31, 2018 and changes during the year ended December 31, 2018 were as follows:

Nonvested Performance Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2018	587.5	$ 64.48
Granted	617.3	67.43
Vested	—	—
Forfeited	(33.5)	65.50
Nonvested as of December 31, 2018	1,171.3	66.01

Monte Carlo Valuation

AEP engages a third party for a Monte Carlo valuation to calculate half of the fair value for the performance units awarded during and after 2017. The valuations use a lattice model and the expected volatility assumptions used were the historical volatilities for AEP and the members of their peer group. The Assumptions used in the Monte Carlo valuations for the years ended December 31, 2018 and 2017 were as follows:

Monte Carlo Valuation	Years Ended December 31, 2018	2017
Valuation Period (in years) (a)	2.87	2.86
Expected Volatility Minimum	14.77%	15.65%
Expected Volatility Maximum	26.72%	27.19%
Expected Volatility Average	17.90%	19.07%
Dividend Rate (b)	—%	—%
Risk Free Rate	2.34%	1.44%

(a) Period from award date to vesting date.
(b) Equivalent to reinvesting dividends.

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting, except that RSUs granted prior to 2017 that vest to AEP's executive officers are settled in cash. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. For RSUs settled in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs settled in cash, compensation cost is recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting is determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

The HR Committee awarded RSUs, including additional units awarded as dividends, for the years ended December 31, 2018, 2017 and 2016 as follows:

Restricted Stock Units	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands)	260.0	255.8	242.0
Weighted Average Grant Date Fair Value	$ 67.96	$ 65.26	$ 62.88

The total fair value and total intrinsic value of restricted stock units vested during the years ended December 31, 2018, 2017 and 2016 were as follows:

Restricted Stock Units	Years Ended December 31, 2018	2017	2016
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 16.6	$ 16.1	$ 16.4
Intrinsic Value of Restricted Stock Units Vested (a)	19.2	20.0	21.0

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2018 and changes during the year ended December 31, 2018 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2018	529.6	$ 62.13
Granted	260.0	67.96
Vested	(277.5)	59.77
Forfeited	(23.0)	64.84
Nonvested as of December 31, 2018	489.1	66.01

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2018 was $37 million and the weighted average remaining contractual life was 1.65 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested upon grant date. Stock units are settled in cash upon termination of board service or up to 10 years later if the participant so elects. Cash settlements for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. After five years of service on the Board of Directors, non-employee directors receive contributions to an AEP stock fund awarded under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investments that are similar to the investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan.

Management records compensation cost for stock units when the units are awarded and adjusts the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

For the years ended December 31, 2018, 2017 and 2016, cash settlements for stock unit distributions were immaterial.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2018, 2017 and 2016 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands)	11.4	14.8	19.1
Weighted Average Grant Date Fair Value	$ 70.41	$ 70.79	$ 64.96

Share-based Compensation Plans

For share-based payment arrangements the compensation cost, the actual tax benefit from the tax deductions for compensation cost recognized in income and the total compensation cost capitalized for the years ended December 31, 2018, 2017 and 2016 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2018	2017	2016
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 53.2	$ 79.5	$ 66.5
Actual Tax Benefit (b)	7.7	18.9	23.3
Total Compensation Cost Capitalized	19.7	26.4	20.8

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.
(b) In December 2017, Tax Reform modified Section 162(m) of the Internal Revenue Code. Beginning after 2017, AEP can no longer deduct certain compensation expense in excess of $1 million for certain named executive officers. This will reduce the tax benefit going forward.

As of December 31, 2018, there was $60 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP and Prior Plan. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance units are adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.4 years.

Under the 2015 LTIP and Prior Plan, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. AEP's current practice is to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset AEP's tax withholding obligation.

16. RELATED PARTY TRANSACTIONS

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

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 12 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (PCA) and Bridge Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the following agreements.

- Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that, amongst other things, addresses the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. With the transfer of OPCo's generation assets to AGR in 2014, AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

System Integration Agreement (SIA) (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The following tables show the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2018, 2017 and 2016:

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2018							
Direct Sales to East Affiliates	$ —	$ —	$ 133.2	$ 0.1	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	—
Auction Sales to OPCo (a)	—	—	5.8	7.1	—	—	—
Direct Sales to AEPEP	103.6	—	—	—	—	—	—
Transmission Agreement and Transmission Coordination Agreement Sales	—	591.4	36.4	11.7	3.9	0.9	26.9
Other Revenues	1.6	7.5	6.0	3.2	17.1	4.5	1.5
Total Affiliated Revenues	$ 105.2	$ 598.9	$ 181.4	$ 22.1	$ 21.0	$ 5.4	$ 28.4

Related Party Revenues	AEP Texas	AEPTCo		APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Year Ended December 31, 2017								
Direct Sales to East Affiliates	$ —	$ —		$ 130.4	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—		—	3.8	—	—	—
Auction Sales to OPCo (a)	—	—		1.0	—	—	—	—
Direct Sales to AEPEP	63.6	—		—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	559.6	(b)	34.1	(4.4)	6.2	—	24.2
Other Revenues	2.1	8.5		6.5	2.4	18.2	4.3	1.9
Total Affiliated Revenues	$ 65.7	$ 568.1		$ 172.0	$ 1.8	$ 24.4	$ 4.3	$ 25.9

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2016							
Direct Sales to East Affiliates	$ —	$ —	$ 126.0	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	3.7
Auction Sales to OPCo (a)	—	—	9.2	12.0	—	—	—
Direct Sales to AEPEP	73.9	—	—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	366.1	1.3	12.2	(2.0)	(1.7)	19.4
Other Revenues	1.8	—	5.6	2.0	19.3	4.3	1.6
Total Affiliated Revenues	$ 75.7	$ 366.1	$ 142.1	$ 26.2	$ 17.3	$ 2.6	$ 24.5

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.
(b) Reflects the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The following tables show the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2018, 2017 and 2016. AEP Texas, AEPTCo, APCo and SWEPCo did not purchase any power from affiliates for the years ended December 31, 2018, 2017 and 2016.

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2018			
Auction Purchases from AEPEP (a)	$ —	$ 79.7	$ —
Auction Purchases from AEP Energy (a)	—	41.0	—
Auction Purchases from AEPSC (a)	—	14.6	—
Direct Purchases from AEGCo	237.9	—	—
Total Affiliated Purchases	$ 237.9	$ 135.3	$ —

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2017			
Auction Purchases from AEPEP (a)	$ —	$ 96.5	$ —
Auction Purchases from AEP Energy (a)	—	5.5	—
Auction Purchases from AEPSC (a)	—	6.5	—
Direct Purchases from AEGCo	223.9	—	—
Total Affiliated Purchases	$ 223.9	$ 108.5	$ —

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2016			
Direct Purchases from West Affiliates	$ —	$ —	$ 3.7
Auction Purchases from AEPEP (a)	—	110.1	—
Auction Purchases from AEP Energy (a)	—	7.7	—
Auction Purchases from AEPSC (a)	—	24.1	—
Direct Purchases from AEGCo	228.6	—	—
Total Affiliated Purchases	$ 228.6	$ 141.9	$ 3.7

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

Transmission Agreement (TA) and Transmission Coordination Agreement (TCA) (Applies to all Registrant Subsidiaries except AEP Texas)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the TA, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis.

The following table shows the net charges recorded by APCo, I&M and OPCo for the years ended December 31, 2018, 2017 and 2016 related to the TA:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
APCo	$ 128.3	$ 158.2	$ 103.2
I&M	91.4	103.8	53.0
OPCo	210.1	248.6	143.6

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP.

The following table shows the net (revenues) expenses allocated among parties to the TCA pursuant to the SPP OATT protocols as described above for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
Company	**2018**	**2017**	**2016**
		(in millions)	
PSO	$ 65.9	$ 56.0	$ 19.6
SWEPCo	10.5	6.6	(19.6)

The net revenues shown above are recorded in Sales to AEP Affiliates on the statements of income and the net expenses are recorded in Other Operation expenses on the statements of income.

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. AEPTCo recorded affiliated transmission revenues related to the TA and TCA in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

ERCOT Transmission Service Charges (Applies to AEP and AEP Texas)

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $27 million, $30 million and $29 million for transmission services in 2018, 2017 and 2016, respectively. The billings are recorded in Other Operation expenses on AEP Texas' statements of income.

Oklaunion PPA between AEP Texas and AEPEP (Applies to AEP Texas)

In 2007, AEP Texas entered into a PPA with an affiliate, AEPEP, whereby AEP Texas agrees to sell AEPEP 100% of AEP Texas' capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Power Station. AEPEP pays AEP Texas for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. There are no penalties if AEP Texas fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC. AEP Texas recognizes revenues for the fuel, operations and maintenance and all other taxes as-billed. Revenue is recognized for the capacity and depreciation billed to AEPEP, on a straight-line basis over the term of the PPA as these represent the minimum payments due. In September 2018, the co-owners of Oklaunion Power Station voted to close the plant in 2020. Effective October 2018, AEP Texas increased depreciation expense to ensure the plant balances are fully depreciated as of September 2020 and recovered through the PPA billings to AEPEP. Under the early termination provisions of the PPA, AEPEP expects to pay AEP Texas the full Property, Plant and Equipment balance through depreciation payments over the remaining period of operation of the plant, which is currently estimated to be September 2020.

AEP Texas recorded revenue of $104 million, $64 million and $74 million from AEPEP for the years ended December 31, 2018, 2017 and 2016, respectively. These amounts are included in Sales to AEP Affiliates on AEP Texas' statements of income.

Joint License Agreement (Applies to AEPTCo, I&M, KPCo, OPCo and PSO)

AEPTCo entered into a 50-year joint license agreement with I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. After the expiration of the agreement, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. For the years ended December 31, 2018, 2017 and 2016, AEPTCo recorded the following costs in Other Operation expense related to these agreements:

	Years Ended December 31,		
Billing Company	**2018**	**2017**	**2016**
		(in millions)	
I&M	$ 2.2	$ 1.4	$ 0.8
KPCo	0.2	0.2	0.1
OPCo	2.9	2.4	2.3
PSO	0.3	0.3	0.2

I&M, KPCo, OPCo and PSO recorded income related to these agreements in Sales to AEP Affiliates on the statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements (UPA) (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading costs were $12 million, $10 million and $13 million in 2018, 2017 and 2016, respectively. I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance costs in 2018, 2017 and 2016 were as follows:

	Years Ended December 31,		
Company	2018	2017	2016
		(in millions)	
I&M	$ 1.5	$ 1.3	$ 1.7
PSO	0.7	0.5	0.6
SWEPCo	3.4	3.5	3.3

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

	Years Ended December 31,		
Company	2018	2017	2016
		(in millions)	
AEGCo	$ 19.9	$ 15.3	$ 14.8
AGR	—	0.1	0.3
APCo	35.1	37.2	36.9
KPCo	4.2	5.0	5.3
WPCo	4.2	5.0	4.8

Central Machine Shop (Applies to APCo, I&M, PSO and SWEPCo)

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

	Years Ended December 31,		
Company	2018	2017	2016
		(in millions)	
AGR	$ 1.6	$ 1.2	$ 2.0
I&M	2.4	2.7	2.9
KPCo	1.7	1.8	1.5
PSO	0.5	1.1	0.5
SWEPCo	0.7	0.8	0.9

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value, for the years ended December 31, 2018, 2017 and 2016:

Sales

	Years Ended December 31,		
Company	**2018**	**2017**	**2016**
		(in millions)	
AEP Texas	$ 0.3	$ 0.2	$ 0.3
APCo	5.4	3.5	4.5
I&M	8.2	5.0	5.2
OPCo	10.7	2.9	1.9
PSO	1.0	1.5	7.5
SWEPCo	0.8	0.5	1.0

Purchases

	Years Ended December 31,		
Company	**2018**	**2017**	**2016**
		(in millions)	
AEP Texas	$ 0.1	$ 0.4	$ 0.7
AEPTCo	18.5	9.1	6.5
APCo	0.6	0.9	1.5
I&M	2.0	3.5	2.7
OPCo	2.8	1.6	1.7
PSO	1.3	0.2	3.2
SWEPCo	0.8	0.4	6.5

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

17. VARIABLE INTEREST ENTITIES

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

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.

AEP is the primary beneficiary of Sabine, DCC Fuel, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, AEP Credit, a protected cell of EIS, Transource Energy and Desert Sky and Trent. In addition, AEP has not provided material financial or other support to any of these entities that was not previously contractually required. AEP holds a significant variable interest in DHLC, OVEC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Consolidated Variable Interests Entities (Applies to all Registrants except AEPTCo and PSO)

Sabine

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2018, 2017 and 2016 were $152 million, $137 million and $162 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

DCC Fuel

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2018, 2017 and 2016 were $113 million, $136 million and $101 million, respectively. The leases were recorded as capital leases on I&M's balance sheets as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. The securitized bonds totaled $791 million and $1 billion as of December 31, 2018 and 2017, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Transition Funding has securitized transition assets of $637 million and $870 million as of December 31, 2018 and 2017, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $48 million and $95 million as of December 31, 2018 and 2017, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $13 million and $38 million as of December 31, 2018 and 2017, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's balance sheets.

Appalachian Consumer Rate Relief Funding

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $272 million and $296 million as of December 31, 2018 and 2017, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $259 million and $282 million as of December 31, 2018 and 2017, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third-party financings. Any third-party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 14.

EIS

AEP's subsidiaries participate in one protected cell of EIS for approximately seven lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2018, 2017 and 2016 was $34 million, $29 million and $28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. Transource Energy's activities consist of the development, construction and operation of FERC-regulated transmission assets in Missouri, West Virginia, Pennsylvania and Maryland. Transource Energy has a credit facility agreement where borrowings are loaned through intercompany lending agreements to its subsidiaries. The creditor to the agreement has no recourse to the general credit of AEP. Transource Energy's credit facility agreement contains certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. For the years ended December 31, 2018, 2017 and 2016, AEP provided capital contributions to Transource Energy of $4 million, $5 million and $45 million, respectively. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

Desert Sky Wind Farm LLC and Trent Wind Farm LLC

Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively "the LLCs") were established for the purpose of repowering, owning and operating 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 the LLCs are VIEs and that AEP is the primary beneficiary based on its power to direct the activities that most significantly impact their economic performance. Also in January 2018, the LLCs 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, the LLCs 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 the LLCs' assets and liabilities on the balance sheets.

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 July 2020 for Trent Wind Farm LLC and August 2020 for Desert Sky Wind Farm LLC. 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 July 2021 for Trent Wind Farm LLC and August 2021 for Desert Sky Wind Farm LLC. 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 December 31, 2018, AEP recorded $69 million of Redeemable Noncontrolling Interest in Mezzanine Equity on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2018

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**OPCo Ohio Phase-in-Recovery Funding**	**APCo Appalachian Consumer Rate Relief Funding**
			(in millions)		
ASSETS					
Current Assets	$ 70.0	$ 77.6	$ 192.8	$ 29.5	$ 24.8
Net Property, Plant and Equipment	106.9	122.3	—	—	—
Other Noncurrent Assets	98.5	58.4	683.5 (a)	24.2 (b)	261.8 (c)
Total Assets	$ 275.4	$ 258.3	$ 876.3	$ 53.7	$ 286.6
LIABILITIES AND EQUITY					
Current Liabilities	$ 31.1	$ 77.1	$ 271.9	$ 48.5	$ 28.0
Noncurrent Liabilities	244.0	181.2	586.1	3.9	256.7
Equity	0.3	—	18.3	1.3	1.9
Total Liabilities and Equity	$ 275.4	$ 258.3	$ 876.3	$ 53.7	$ 286.6

(a) Includes an intercompany item eliminated in consolidation of $47 million.
(b) Includes an intercompany item eliminated in consolidation of $11 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2018

	Other Consolidated VIEs			
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Desert Sky and Trent**
		(in millions)		
ASSETS				
Current Assets	$ 974.2	$ 177.8	$ 25.7	$ 6.8
Net Property, Plant and Equipment	—	—	380.3	348.5
Other Noncurrent Assets	6.3	0.1	1.9	—
Total Assets	$ 980.5	$ 177.9	$ 407.9	$ 355.3
LIABILITIES AND EQUITY				
Current Liabilities	$ 923.5	$ 38.6	$ 19.9	$ 8.7
Noncurrent Liabilities	0.8	85.3	160.3	6.2
Equity	56.2	54.0	227.7	340.4
Total Liabilities and Equity	$ 980.5	$ 177.9	$ 407.9	$ 355.3

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2017

	Registrant Subsidiaries				
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding
			(in millions)		
ASSETS					
Current Assets	$ 56.3	$ 102.5	$ 191.7	$ 28.7	$ 22.3
Net Property, Plant and Equipment	113.2	179.9	—	—	—
Other Noncurrent Assets	90.2	86.3	923.5 (a)	71.0 (b)	285.6 (c)
Total Assets	$ 259.7	$ 368.7	$ 1,115.2	$ 99.7	$ 307.9
LIABILITIES AND EQUITY					
Current Liabilities	$ 49.1	$ 96.5	$ 260.9	$ 47.9	$ 27.6
Noncurrent Liabilities	211.0	272.2	836.1	50.5	278.4
Equity	(0.4)	—	18.2	1.3	1.9
Total Liabilities and Equity	$ 259.7	$ 368.7	$ 1,115.2	$ 99.7	$ 307.9

(a) Includes an intercompany item eliminated in consolidation of $54 million.
(b) Includes an intercompany item eliminated in consolidation of $33 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2017

	Other Consolidated VIEs		
	AEP Credit	Protected Cell of EIS	Transource Energy
		(in millions)	
ASSETS			
Current Assets	$ 926.3	$ 178.7	$ 17.4
Net Property, Plant and Equipment	—	—	323.9
Other Noncurrent Assets	6.4	—	3.1
Total Assets	$ 932.7	$ 178.7	$ 344.4
LIABILITIES AND EQUITY			
Current Liabilities	$ 872.0	$ 36.4	$ 12.4
Noncurrent Liabilities	0.7	95.2	132.0
Equity	60.0	47.1	200.0
Total Liabilities and Equity	$ 932.7	$ 178.7	$ 344.4

Non-Consolidated Significant Variable Interests

DHLC

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2018, 2017 and 2016 were $58 million, $61 million and $65 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2018		2017	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	14.5	14.5	11.8	11.8
SWEPCo's Share of Obligations	—	167.6	—	144.3
Total Investment in DHLC	$ 22.1	$ 189.7	$ 19.4	$ 163.7

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2018, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2018 and 2017, OVEC's outstanding indebtedness was approximately $1.4 billion and $1.4 billion, respectively. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and its subsidiary holds a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors and Operating Committee of OVEC.

AEP's investment in OVEC was:

	December 31,			
	2018		2017	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Ratio of OVEC Debt (a)	—	604.1	—	626.3
Total Investment in OVEC	$ 4.4	$ 608.5	$ 4.4	$ 630.7

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt was $218 million, $109 million and $277 million as of December 31, 2018 and $226 million, $113 million and $287 million as of December 31, 2017, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity for Resale on the statements of income and is shown in the table below:

	Years Ended December 31,		
Company	2018	2017	2016
	(in millions)		
APCo	$ 100.4	$ 101.0	$ 88.0
I&M	50.2	50.5	44.0
OPCo	127.5	128.2	111.7

Potomac-Appalachian Transmission Highline, LLC (PATH)

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in PATH. PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the "Allegheny Series." AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP's equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP's subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case were unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at the FERC were held in March and April 2015. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the ALJ issued an advisory Initial Decision. Additional briefing was submitted during the fourth quarter of 2015. In January 2017, the FERC issued its order on Initial Decision, adopting in part and rejecting in part the ALJ's recommendations. The FERC order included (a) a finding that the PATH Project's abandonment costs were prudently incurred, (b) a finding that the disposition of certain assets was prudent, (c) guidance regarding the future disposition of assets, (d) a reduction of PATH WV's authorized ROE to 8.11% prospectively only after the date of the order, (e) an adjustment of the amortization period to end December 2017, and (f) a credit for certain amounts that were deemed to be not includable in PATH-WV's formula rates.

In February 2017, the PATH Companies filed a request for rehearing of two adverse rulings in the January 2017 FERC order. The request seeks the FERC to reverse its reduction of the PATH Companies 10.4% ROE for the period after January 19, 2017 and to allow the recovery of certain education and outreach costs disallowed by the order. In February 2017, the Edison Electric Institute ("EEI") also filed a request for rehearing recommending reversal of the January 2017 FERC ordered ROE reduction and cost disallowance. The requests for rehearing by the PATH Companies and EEI are currently pending before the FERC. The requests for rehearing do not impact the recovery of costs by the PATH Companies under their formula rates or the timing of the compliance filing required by the order, which was filed in March 2017, and updated in May 2017 and August 2017. As a result of the January 2017 FERC order, PATH-WV is required to refund certain amounts that have been collected under its formula rate in its 2018 Projected Transmission Revenue Requirement. PATH-WV refunded $11.4 million in 2018, including carrying charges, related to the January 2017 order in its 2018 Projected Transmission Revenue Requirement.

In January 2019, FERC issued an order on the PATH Companies' formula rate compliance filing requesting additional information regarding certain additional costs that may be required to be refunded.

AEP's investment in PATH-WV was:

	December 31,			
	2018		2017	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 18.8	$ 18.8	$ 18.8	$ 18.8
Retained Earnings	(1.4)	(1.4)	(2.0)	(2.0)
Total Investment in PATH-WV	$ 17.4	$ 17.4	$ 16.8	$ 16.8

AEP's investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows and impact financial condition.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	2018	2017	2016
	(in millions)		
AEP Texas	$ 184.3	$ 152.6	$ 142.3
AEPTCo	220.4	188.9	131.1
APCo	295.6	268.8	244.2
I&M	173.5	176.0	147.7
OPCo	214.9	195.7	181.1
PSO	121.5	114.7	111.0
SWEPCo	164.4	150.7	147.0

The carrying amount and classification of variable interest in AEPSC's accounts payable were as follows:

Company	December 31, 2018 As Reported on the Balance Sheet	2018 Maximum Exposure	2017 As Reported on the Balance Sheet	2017 Maximum Exposure
	(in millions)			
AEP Texas	$ 22.3	$ 22.3	$ 24.2	$ 24.2
AEPTCo	24.6	24.6	25.1	25.1
APCo	32.2	32.2	37.0	37.0
I&M	23.8	23.8	26.8	26.8
OPCo	23.9	23.9	27.4	27.4
PSO	13.2	13.2	18.7	18.7
SWEPCo	18.4	18.4	20.8	20.8

AEGCo

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2018, 2017 and 2016 were $238 million, $224 million and $229 million, respectively. The carrying amount of I&M's liabilities associated with AEGCo as of December 31, 2018 and 2017 was $20 million and $23 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. See "Rockport Lease" section of Note 13 for additional information.

18. PROPERTY, PLANT AND EQUIPMENT

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

Property, Plant and Equipment is shown functionally on the face of the Registrants' balance sheets. The following tables include the Registrants' total plant balances as of December 31, 2018 and 2017:

December 31, 2018	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 20,989.1	(a)	$ —	$ —	$ 6,509.6	$ 4,887.2	$ —	$ 1,577.0	$ 4,672.6	(a)
Transmission	21,500.5		3,683.6	6,515.8	3,317.7	1,576.8	2,544.3	892.3	1,866.9	
Distribution	21,192.8		4,043.2	—	3,989.4	2,249.7	4,942.3	2,572.8	2,178.6	
Other	3,770.8		724.6	172.6	457.4	543.1	563.7	298.1	485.2	
CWIP	4,352.6	(a)	836.0	1,578.3	490.2	465.3	432.1	94.0	194.7	(a)
Less: Accumulated Depreciation	17,743.1		1,431.2	271.9	4,118.9	3,139.4	2,217.7	1,472.1	2,633.5	
Total Regulated Property, Plant and Equipment - Net	54,062.7		7,856.2	7,994.8	10,645.4	6,582.7	6,264.7	3,962.1	6,764.5	
Nonregulated Property, Plant and Equipment - Net	1,036.4		135.6	1.4	22.9	28.5	10.2	4.6	107.3	
Total Property, Plant and Equipment - Net	$ 55,099.1		$ 7,991.8	$ 7,996.2	$ 10,668.3	$ 6,611.2	$ 6,274.9	$ 3,966.7	$ 6,871.8	

December 31, 2017	AEP		AEP Texas	AEPTCo (b)	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 20,406.5	(a)	$ —	$ —	$ 6,446.9	$ 4,445.9	$ —	$ 1,577.2	$ 4,624.9	(a)
Transmission	18,942.3		3,053.6	5,319.7	3,019.9	1,504.0	2,419.2	858.8	1,679.8	
Distribution	19,865.9		3,718.6	—	3,763.8	2,069.3	4,626.4	2,445.1	2,095.8	
Other	3,224.8		457.6	125.4	399.5	552.3	485.5	282.0	416.8	
CWIP	3,972.6	(a)	834.4	1,324.0	483.0	460.2	410.1	111.3	220.7	(a)
Less: Accumulated Depreciation	16,906.7		1,399.4	152.6	3,891.1	3,011.7	2,183.9	1,393.6	2,520.5	
Total Regulated Property, Plant and Equipment - Net	49,505.4		6,664.8	6,616.5	10,222.0	6,020.0	5,757.3	3,880.8	6,517.5	
Nonregulated Property, Plant and Equipment - Net	756.1		160.3	1.4	23.1	30.4	9.5	5.4	114.5	
Total Property, Plant and Equipment - Net	$ 50,261.5		$ 6,825.1	$ 6,617.9	$ 10,245.1	$ 6,050.4	$ 5,766.8	$ 3,886.2	$ 6,632.0	

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

(b) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

Functional Class of Property	2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate Ranges	2016 Depreciable Life Ranges (in years)
Generation	2.4% - 4.0%	20 - 132	2.3% - 3.7%	20 - 132	2.1% - 4.0%	35 - 132
Transmission	1.6% - 2.7%	15 - 81	1.6% - 2.7%	15 - 100	1.5% - 2.7%	15 - 100
Distribution	2.7% - 3.6%	7 - 78	2.7% - 3.7%	5 - 156	2.6% - 3.7%	7 - 156
Other	2.3% - 9.8%	5 - 75	2.3% - 9.2%	5 - 84	3.1% - 8.6%	5 - 84

AEP Texas

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Transmission	1.7%	45 - 81	1.7%	45 - 81	1.8%	45 - 81
Distribution	3.6%	7 - 70	3.6%	7 - 70	3.3%	7 - 70
Other	6.0%	5 - 50	8.7%	5 - 50	8.3%	5 - 50

AEPTCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Transmission	1.9%	20 - 75	1.7%	20 - 100	1.6%	20 - 100

APCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	3.1%	35 - 112	3.1%	35 - 112	3.1%	35 - 121
Transmission	1.6%	15 - 68	1.6%	15 - 68	1.5%	15 - 68
Distribution	3.6%	10 - 57	3.7%	10 - 57	3.7%	10 - 57
Other	7.4%	5 - 55	6.5%	5 - 55	6.0%	5 - 55

I&M

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	3.4%	20 - 132	2.4%	20 - 132	2.4%	59 - 132
Transmission	1.8%	50 - 73	1.7%	50 - 75	1.7%	50 - 75
Distribution	3.1%	9 - 75	2.7%	10 - 70	2.8%	10 - 70
Other	8.9%	5 - 50	8.4%	5 - 45	8.6%	5 - 45

OPCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	3.0%	14 - 65	2.8%	5 - 57	2.8%	7 - 57
Other	6.3%	5 - 50	6.2%	5 - 50	5.9%	5 - 50

PSO

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	2.9%	35 - 75	2.4%	35 - 85	2.4%	35 - 85
Transmission	2.3%	45 - 75	2.2%	45 - 100	2.2%	45 - 100
Distribution	2.9%	15 - 78	2.7%	27 - 156	2.7%	27 - 156
Other	6.3%	5 - 64	7.4%	5 - 84	6.4%	5 - 84

SWEPCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	2.4%	40 - 70	2.3%	40 - 70	2.1%	40 - 70
Transmission	2.2%	50 - 73	2.3%	50 - 73	2.2%	50 - 70
Distribution	2.7%	25 - 70	2.7%	25 - 70	2.6%	25 - 65
Other	8.0%	5 - 55	7.2%	5 - 55	6.8%	5 - 51

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP and AEP Texas. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo for 2018, 2017 and 2016.

Functional Class of Property	2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate Ranges	2016 Depreciable Life Ranges (in years)
Generation	3.4% - 22.3%	15 - 59	2.4% - 5.1%	15 - 66	2.8% - 17.2%	40 - 66
Transmission	2.4%	40	0.2%	40	2.3%	43 - 55
Distribution	2.3%	40	2.3%	40	1.3%	40 - 50
Other	16.3%	5 - 50 (a)	12.1%	5 - 50 (a)	9.1%	5 - 50 (a)

(a) SWEPCo's nonregulated property, plant and equipment is depreciated using the straight-line method over a range of 3 to 20 years.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities. I&M records ARO for the decommissioning of the Cook Plant. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

As of December 31, 2018 and 2017, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.66 billion and $1.30 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2018 and 2017, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.16 billion and $2.22 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2018 and 2017 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2017	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2018
			(in millions)			
AEP (b)(c)(d)(e)	$ 2,005.7	$ 93.7	$ 0.8	$ (87.0)	$ 342.3 (f)	$ 2,355.5
AEP Texas (b)(e)	26.7	1.2	—	(0.1)	0.1	27.9
APCo (b)(e)	125.0	6.6	—	(17.3)	1.8	116.1
I&M (b)(c)(e)	1,321.8	58.7	—	(0.2)	301.0 (f)	1,681.3
OPCo (e)	1.7	0.1	—	—	—	1.8
PSO (b)(e)	54.0	3.2	—	(0.4)	(9.9)	46.9
SWEPCo (b)(d)(e)	169.2	9.1	0.2	(11.7)	40.0	206.8

Company	ARO as of December 31, 2016	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2017
			(in millions)			
AEP (b)(c)(d)(e)	$ 1,934.9	$ 90.9	$ 2.4	$ (104.5)	$ 82.0	$ 2,005.7
AEP Texas (b)(e)	25.5	1.2	—	(0.1)	0.1	26.7
APCo (b)(e)	127.1	7.0	—	(21.7)	12.6	125.0
I&M (b)(c)(e)	1,258.1	55.9	—	(0.1)	7.9	1,321.8
OPCo (e)	1.7	0.1	—	(0.1)	—	1.7
PSO (b)(e)	53.4	3.1	—	(0.5)	(2.0)	54.0
SWEPCo (b)(d)(e)	156.5	8.3	—	(0.3)	4.7	169.2

(a) Primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.66 billion and $1.30 billion as of December 31, 2018 and 2017, respectively.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Revision for Cook Plant related to a new third-party study, which impacted the ARO liability for changes of estimated cash flows and application of a new discount rate.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
AEP	$ 132.5	$ 93.7	$ 113.2
AEP Texas	20.0	6.8	9.2
AEPTCo	70.6	49.0 (a)	52.3
APCo	13.2	9.2	11.7
I&M	11.9	11.1	15.3
OPCo	9.8	6.4	6.0
PSO	0.4	0.5	6.2
SWEPCo	6.0	2.4	11.0

(a) The amount presented reflects the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
AEP	$ 73.6	$ 48.6	$ 51.7
AEP Texas	18.4	6.8	5.9
AEPTCo	26.1	20.2	15.6
APCo	8.4	5.3	6.3
I&M	7.4	6.7	7.2
OPCo	5.8	3.8	3.3
PSO	0.9	1.1	3.4
SWEPCo	4.8	2.1	6.9

Jointly-owned Electric Facilities (Applies to AEP, AEP Texas, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and non-affiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2018		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a)(i)(j)	Coal	83.5%	$ 16.4	$ 0.2	$ 2.4
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	336.2	5.1	209.6
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	591.3	16.6	418.0
Oklaunion Power Station (f)	Coal	70.3%	106.4	—	67.8
Turk Generating Plant (h)(k)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 3,015.9	$ 24.6	$ 984.2
AEP Texas					
Oklaunion Power Station (f)	Coal	54.7%	$ 352.1	$ 0.2	$ 218.6
I&M					
Rockport Generating Plant (c)(d)(e)	Coal	50.0%	$ 1,108.7	$ 50.2	$ 514.1
PSO					
Oklaunion Power Station (f)	Coal	15.6%	$ 106.4	$ —	$ 67.8
SWEPCo					
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	$ 336.2	$ 5.1	$ 209.6
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	591.3	16.6	418.0
Turk Generating Plant (h)(k)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 2,893.1	$ 24.4	$ 914.0

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2017 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a)(i)(j)	Coal	83.5%	$ 2.1	$ 4.2	$ 0.1
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	343.1	5.3	214.2
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	364.8	8.9	81.6
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	589.8	7.8	406.3
Oklaunion Power Station (f)	Coal	70.3%	456.4	1.9	254.6
Turk Generating Plant (h)(k)	Coal	73.3%	1,580.4	3.2	166.6
Transmission (l)	NA	(b)	62.7	0.3	46.1
Total			$ 3,399.3	$ 31.6	$ 1,169.5
AEP Texas					
Oklaunion Power Station (f)	Coal	54.7%	$ 350.7	$ 1.3	$ 194.1
I&M					
Rockport Generating Plant (c)(d)(e)	Coal	50.0%	$ 1,093.9	$ 28.2	$ 562.6
PSO					
Oklaunion Power Station (f)	Coal	15.6%	$ 105.7	$ 0.6	$ 60.5
SWEPCo					
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	$ 343.1	$ 5.3	$ 214.2
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	364.8	8.9	81.6
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	589.8	7.8	406.3
Turk Generating Plant (h)(k)	Coal	73.3%	1,580.4	3.2	166.6
Total			$ 2,878.1	$ 25.2	$ 868.7

(a) Operated by AGR.
(b) Varying percentages of ownership.
(c) Operated by I&M.
(d) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a non-affiliated company. See the "Rockport Lease" section of Note 13.
(e) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.
(f) Operated by PSO, which owns 15.6%. Also jointly-owned (54.7%) by AEP Texas and various non-affiliated companies. See the "Impairments" section of Note 7.
(g) Operated by CLECO, a non-affiliated company.
(h) Operated by SWEPCo.
(i) Conesville Generating Station, Unit 4 was impaired as of September 30, 2016. See the "Impairments" section of Note 7.
(j) In accordance with the Asset Purchase Agreement between AGR and Dynegy Corporation dated February 2017, AGR acquired Dynegy Corporation's 40% ownership interest in Conesville Generating Station, Unit 4. Subsequent to this transaction, AGR's ownership percentage in Conesville Generating Station, Unit 4 is 83.5%.
(k) In December 2017, SWEPCo recorded a $15 million pretax impairment related to the Louisiana jurisdictional share of Turk Plant. Amount reflects the impact of the impairment. See the "Impairments" section of Note 7.
(l) In accordance with the 2017 CCD Transmission Asset Exchange Agreement between OPCo, Dayton Power & Light Company and Duke Energy Ohio, Inc., the parties agreed to an exchange and transfer of jointly owned transmission assets in order to eliminate the joint ownership of these assets. The asset exchange closed on June 30, 2018, ending the joint ownership of these transmission assets.
NA Not applicable.

19. GOODWILL

The disclosure in this note applies to AEP only.

The changes in AEP's carrying amount of goodwill for the years ended December 31, 2018 and 2017 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2016	$ 37.1	$ 15.4	$ 52.5
Impairment Losses	—	—	—
Balance as of December 31, 2017	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2018	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2018 and 2017, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

20. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The table below represents AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 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	$ 3,751.8	$ 2,189.2	$ —	$ —	$ —	$ —	$ 5,941.0
Commercial Revenues	2,206.4	1,273.4	—	—	—	—	3,479.8
Industrial Revenues	2,190.2	494.5	—	—	—	—	2,684.7
Other Retail Revenues	183.1	39.2	—	—	—	—	222.3
Total Retail Revenues	8,331.5	3,996.3	—	—	—	—	12,327.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues (a)	899.8	—	—	544.4	—	(226.0)	1,218.2
Transmission Revenues (b)	282.2	372.1	849.3	—	—	(737.1)	766.5
Marketing, Competitive Retail and Renewable Revenues	—	—	—	1,353.0	—	—	1,353.0
Total Wholesale and Competitive Retail Revenues	1,182.0	372.1	849.3	1,897.4	—	(963.1)	3,337.7
Other Revenues from Contracts with Customers (c)	158.4	204.6	15.2	20.6	86.2	(32.0)	453.0
Total Revenues from Contracts with Customers	9,671.9	4,573.0	864.5	1,918.0	86.2	(995.1)	16,118.5
Other Revenues:							
Alternative Revenues (c)	(15.9)	(22.2)	(60.4)	—	—	52.7	(45.8)
Other Revenues (c)	(10.5)	102.3	—	22.3	8.9	—	123.0
Total Other Revenues	(26.4)	80.1	(60.4)	22.3	8.9	52.7	77.2
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $121 million. The remaining affiliated amounts were immaterial.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $643 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues.

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Year Ended December 31, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 578.9	$ —	$ 1,342.6	$ 730.0	$ 1,611.5	$ 659.0	$ 641.5
Commercial Revenues	436.2	—	582.4	490.3	835.7	404.4	491.9
Industrial Revenues	110.0	—	602.4	560.3	385.2	294.1	325.8
Other Retail Revenues	25.9	—	77.4	7.2	12.9	83.3	8.6
Total Retail Revenues	1,151.0	—	2,604.8	1,787.8	2,845.3	1,440.8	1,467.8
Wholesale Revenues:							
Generation Revenues (a)	—	—	250.4	470.5	—	36.3	216.8
Transmission Revenues (b)	313.4	816.9	82.7	23.1	58.5	40.2	108.4
Total Wholesale Revenues	313.4	816.9	333.1	493.6	58.5	76.5	325.2
Other Revenues from Contracts with Customers (c)	28.6	15.1	55.3	99.6	176.1	19.1	24.0
Total Revenues from Contracts with Customers	1,493.0	832.0	2,993.2	2,381.0	3,079.9	1,536.4	1,817.0
Other Revenues:							
Alternative Revenues (d)	(1.3)	(55.9)	(23.8)	(2.1)	(20.8)	10.9	4.9
Other Revenues (d)	103.6	—	(1.9)	(8.2)	4.3	—	—
Total Other Revenues	102.3	(55.9)	(25.7)	(10.3)	(16.5)	10.9	4.9
Total Revenues	$ 1,595.3	$ 776.1	$ 2,967.5	$ 2,370.7	$ 3,063.4	$ 1,547.3	$ 1,821.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $134 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $646 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $70 million primarily relating to the barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues.

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 revenues tables above.

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 Tennessee Regulatory Authority. 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 line in the disaggregated revenues 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 revenues 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.

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 in the disaggregated revenues 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 December 31, 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 Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2019	2020-2021	2022-2023	After 2024	Total
			(in millions)		
AEP	$ 920.7	$ 173.7	$ 162.5	$ 266.3	$ 1,523.2
AEP Texas	332.8	—	—	—	332.8
AEPTCo	893.6	—	—	—	893.6
APCo	144.8	32.2	23.2	—	200.2
I&M	25.6	2.9	2.9	—	31.4
OPCo	65.4	—	—	—	65.4
PSO	17.3	—	—	—	17.3
SWEPCo	35.2	—	—	—	35.2

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 December 31, 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 December 31, 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 December 31, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

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	December 31, 2018	January 1, 2018
	(in millions)	
AEPTCo	$ 58.6	$ 47.1
APCo	52.5	35.6
I&M	35.3	15.1
OPCo	46.1	26.1
PSO	12.4	6.1
SWEPCo	16.3	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 December 31, 2018.

21. UNAUDITED QUARTERLY FINANCIAL INFORMATION

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

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant is as follows:

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo (a)	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
March 31, 2018								
Total Revenues	$ 4,048.3	$ 371.6	$ 191.7	$ 820.4	$ 576.8	$ 790.9	$ 336.8	$ 419.4
Operating Income	706.0	81.8	111.1	193.0	97.4	117.3	3.9	41.6
Net Income (Loss)	456.7	46.8	84.1	125.5	64.2	79.6	(7.2)	13.4
Earnings Attributable to Common Shareholders	454.4	NA	NA	NA	NA	NA	NA	11.8
June 30, 2018								
Total Revenues	$ 4,013.2	$ 388.3	$ 200.1	$ 667.0	$ 589.7	$ 748.8	$ 398.3	$ 457.1
Operating Income	757.0	86.2	110.5	132.6	117.4	104.4	57.2	70.5
Net Income	530.1	46.5	82.0	77.4	94.7	68.8	36.6	38.7
Earnings Attributable to Common Shareholders	528.4	NA	NA	NA	NA	NA	NA	37.6
September 30, 2018								
Total Revenues	$ 4,333.1	$ 433.4	$ 194.4	$ 762.0	$ 629.7	$ 778.3	$ 481.4	$ 535.3
Operating Income	668.6	94.0	97.0	49.8	110.2	79.9	78.5	127.1
Net Income	579.7	57.8	78.1	87.1	72.7	88.7	60.4	89.6
Earnings Attributable to Common Shareholders	577.6	NA	NA	NA	NA	NA	NA	88.2
December 31, 2018								
Total Revenues	$ 3,801.1	$ 402.0	$ 189.9	$ 718.1	$ 574.5	$ 745.4	$ 330.8	$ 410.1
Operating Income	551.1	84.3	91.5	108.1	52.2	118.2	2.9	38.5
Net Income (Loss)	364.8	60.2	71.7	77.8	29.7	88.4	(6.6)	10.5
Earnings Attributable to Common Shareholders	363.4	NA	NA	NA	NA	NA	NA	9.6

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
March 31, 2017								
Total Revenues	$ 3,933.3	$ 343.6	$ 152.7	$ 792.8	$ 560.5	$ 746.1	$ 304.1	$ 401.3
Operating Income (b)	1,085.7	82.3	90.4	218.9	117.2	149.6	19.9	52.8
Net Income	594.2	33.3	57.0	110.6	68.4	86.2	4.8	17.3
Earnings Attributable to Common Shareholders	592.2	NA	NA	NA	NA	NA	NA	16.3
June 30, 2017								
Total Revenues	$ 3,576.5	$ 389.5	$ 229.4	$ 675.3	$ 467.3	$ 663.9	$ 344.7	$ 424.7
Operating Income (b)	733.3	108.8	165.4	126.1	33.6	118.5	45.3	74.1
Net Income	376.2	49.0	107.4	52.1	10.5	62.3	20.4	25.1
Earnings Attributable to Common Shareholders	375.0	NA	NA	NA	NA	NA	NA	24.5
September 30, 2017								
Total Revenues	$ 4,104.7	$ 431.2	$ 165.6	$ 719.3	$ 557.7	$ 742.0	$ 442.8	$ 517.6
Operating Income (b)	975.1	128.8	93.6	171.7	113.6	153.4	85.9	136.0
Net Income	556.7	64.3	58.6	86.0	64.9	82.6	46.2	84.1
Earnings Attributable to Common Shareholders	544.7	NA	NA	NA	NA	NA	NA	73.1
December 31, 2017								
Total Revenues	$ 3,810.4	$ 374.1	$ 159.2	$ 746.8	$ 535.7	$ 731.9	$ 335.6	$ 436.3
Operating Income (b)	730.9	96.2	83.5	173.6	82.8	144.2	20.4	41.1
Net Income	401.8	163.9	47.7	82.6	42.9	92.8	0.6	11.0
Earnings Attributable to Common Shareholders	400.7	NA	NA	NA	NA	NA	NA	10.8

NA Not applicable.

(a) The amounts presented for the Quarterly Periods Ended March 31, 2018 and June 30, 2018 reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously issued Financial Statement" section of Note 1.

(b) Amounts reflect the adoption of ASU 2017-07 "Compensation - Retirement Benefits". See Note 2 - New Accounting Pronouncements for additional information.

AEP

The unaudited quarterly financial information relating to Common Shareholders is as follows:

	2018 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders (in millions)	$ 454.4	$ 528.4	$ 577.6	$ 363.4
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	0.92	1.07	1.17	0.74
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	0.92	1.07	1.17	0.74

	2017 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders (in millions)	$ 592.2	$ 375.0	$ 544.7	$ 400.7
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.20	0.76	1.11	0.81
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.20	0.76	1.10	0.81

(a) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing - The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page - Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings - Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders - (Stock held in a bank or brokerage account) - When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan - A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/stock.

Financial Community Inquiries - Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Individual shareholders should contact Rhonda Owens-Paul, 614-716-2819, rkowens-paul@AEP.com.

Number of Shareholders - As of February 25, 2019, there were approximately 60,000 registered shareholders and approximately 783,000 shareholders holding stock in street name through a bank or broker. There were 493,287,558 shares outstanding as of February 25, 2019.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2018. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at rkowens-paul@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	58	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	53	Executive Vice President - Utilities
Paul Chodak, III	55	Executive Vice President - Generation
David M. Feinberg	49	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	58	Executive Vice President and Chief Administrative Officer
Mark C. McCullough	59	Executive Vice President - Transmission
Charles R. Patton	59	Executive Vice President - External Affairs
Brian X. Tierney	51	Executive Vice President and Chief Financial Officer
Charles E. Zebula	58	Executive Vice President - Energy Supply

Printed with
inks containing
soy and/or
vegetable oils

FSC
www.fsc.org
MIX
Paper from
responsible sources
FSC® C132107