Appendix A to the
Proxy Statement

American Electric Power

2019 Annual Report

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

BOUNDLESS ENERGY℠

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CONTENTS

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.
AEP Wind Holdings LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
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 deregulated 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.
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 single unit coal-fired generation plant totaling 651 MW located in Conesville, Ohio. The plant is jointly owned by AGR and a nonaffiliate.

Term	Meaning
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
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 IX, DCC Fuel X, DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, and DCC Fuel XIV 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.
Equity Units	AEP's Equity Units issued in March 2019.
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.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxics Standards.

Term	Meaning
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.
North Central Wind Energy Facilities	A proposed joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,485 MWs of wind generation.
NO_2	Nitrogen dioxide.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
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.
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.
PTC	Production Tax Credits.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Racine	A generation plant consisting of two hydroelectric generating units totaling 48 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.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.

Term	Meaning
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
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.
Santa Rita East	Santa Rita East Wind Holdings, LLC, a consolidated VIE whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas in which AEP owns a 75% interest.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
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.

Term	Meaning
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.
- Decreased demand for electricity.
- 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 SNF.
- The availability of fuel and necessary generation capacity and the performance of generation plants.
- 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 PM 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 coal ash and 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 coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within RTOs 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, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.

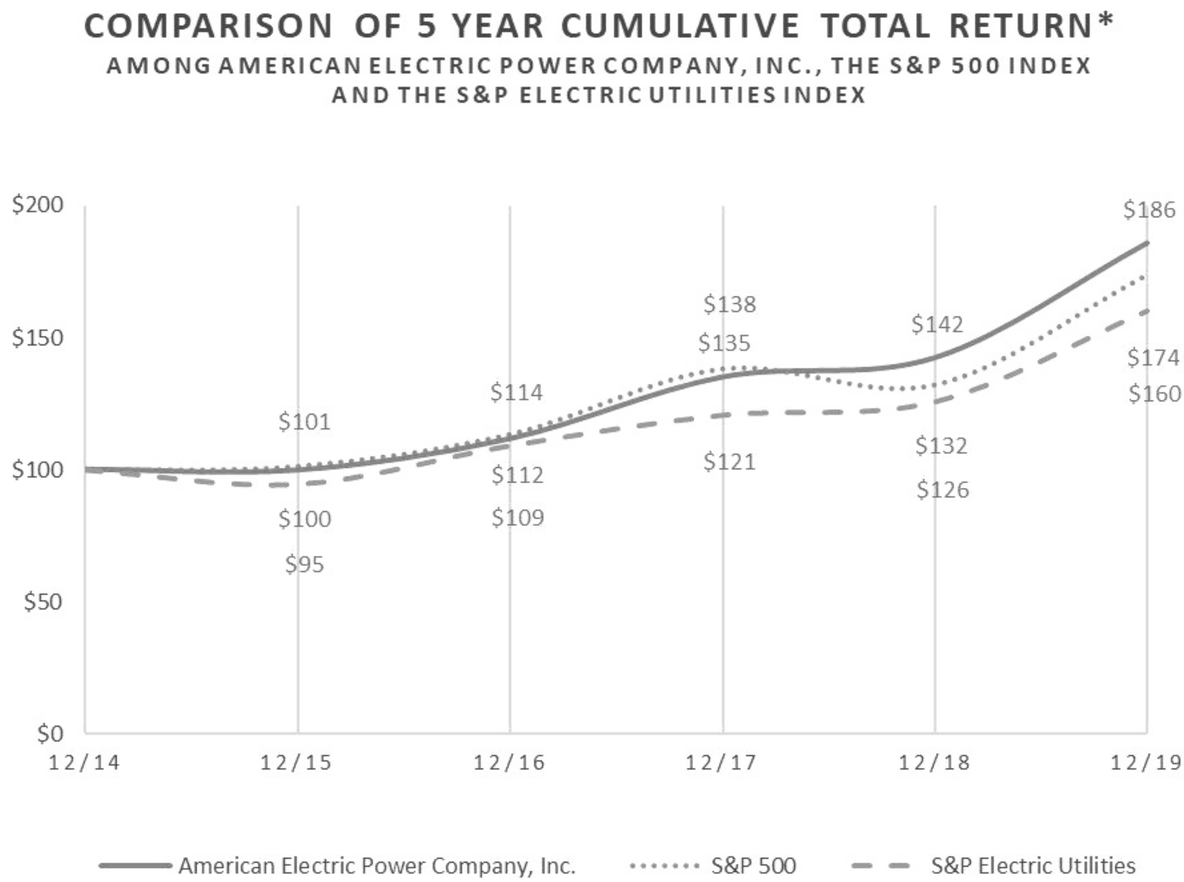
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

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, except as required by law. 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, 2019, AEP had approximately 57,000 registered shareholders.



*$100 invested on 12/31/14 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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

	2019 (a)	2018	2017	2016	2015
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$15,561.4	$16,195.7	$15,424.9	$16,380.1	$16,453.2
Operating Income	$ 2,592.3	$ 2,682.7	$ 3,525.0	$ 1,163.9	$ 3,292.4
Income from Continuing Operations	$ 1,919.8	$ 1,931.3	$ 1,928.9	$ 620.5	$ 1,768.6
Income (Loss) From Discontinued Operations, Net of Tax	—	—	—	(2.5)	283.7
Net Income	1,919.8	1,931.3	1,928.9	618.0	2,052.3
Net Income (Loss) Attributable to Noncontrolling Interest	(1.3)	7.5	16.3	7.1	5.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,921.1	$ 1,923.8	$ 1,912.6	$ 610.9	$ 2,047.1
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$79,145.7	$73,085.2	$67,428.5	$62,036.6	$65,481.4
Accumulated Depreciation and Amortization	19,007.6	17,986.1	17,167.0	16,397.3	19,348.2
Total Property, Plant and Equipment – Net	$60,138.1	$55,099.1	$50,261.5	$45,639.3	$46,133.2
Total Assets	$75,892.3	$68,802.8	$64,729.1	$63,467.7	$61,683.1
Total AEP Common Shareholders' Equity	$19,632.2	$19,028.4	$18,287.0	$17,397.0	$17,891.7
Noncontrolling Interests	$ 281.0	$ 31.0	$ 26.6	$ 23.1	$ 13.2
Long-term Debt (b)	$26,725.5	$23,346.7	$21,173.3	$20,256.4	$19,572.7
Obligations Under Finance Leases (b)	$ 306.8	$ 289.0	$ 297.8	$ 305.5	$ 343.5
Obligations Under Operating Leases (b) (c)	$ 968.7	$ —	$ —	$ —	$ —
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
From Continuing Operations	$ 3.89	$ 3.90	$ 3.89	$ 1.25	$ 3.59
From Discontinued Operations	—	—	—	(0.01)	0.58
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.89	$ 3.90	$ 3.89	$ 1.24	$ 4.17
Weighted Average Number of Basic Shares Outstanding (in millions)	493.7	492.8	491.8	491.5	490.3
Market Price Range:					
High	$ 96.22	$ 81.05	$ 78.07	$ 71.32	$ 65.38
Low	$ 72.26	$ 62.71	$ 61.82	$ 56.75	$ 52.29
Year-end Market Price	$ 94.51	$ 74.74	$ 73.57	$ 62.96	$ 58.27
Cash Dividends Declared per AEP Common Share	$ 2.71	$ 2.53	$ 2.39	$ 2.27	$ 2.15
Dividend Payout Ratio	69.67%	64.87%	61.44%	183.06%	51.56%
Book Value per AEP Common Share	$ 39.73	$ 38.58	$ 37.17	$ 35.38	$ 36.44

(a) The 2019 financial results include pretax asset impairments of $156 million. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.
(b) Includes portion due within one year.
(c) Reflects the adoption of ASU 2016-02 "Accounting for Leases." See Note 2 - New Accounting Standards and Note 13 - Leases 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:

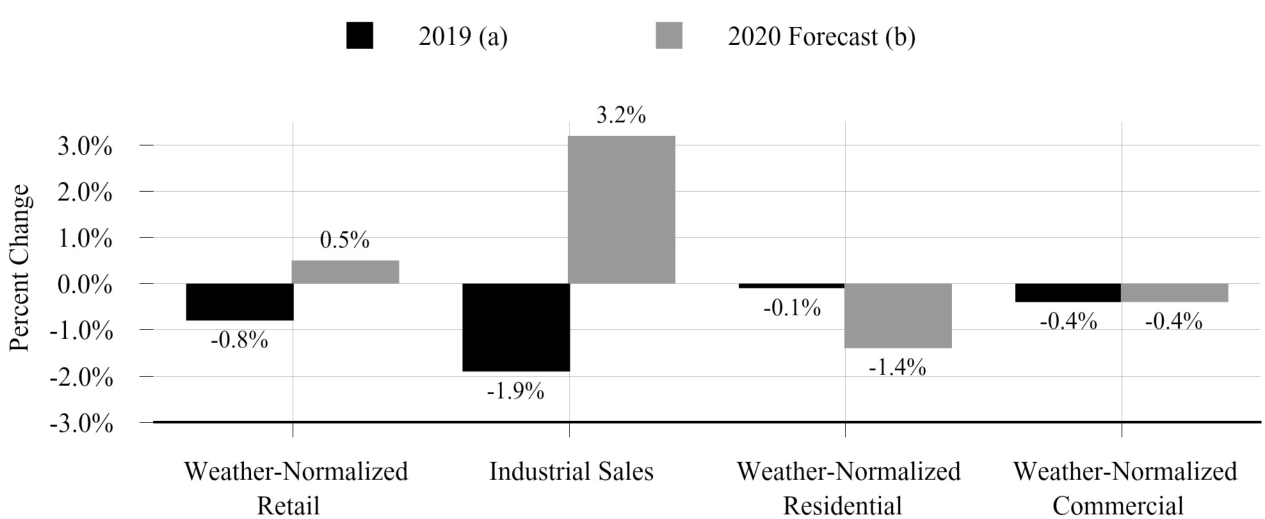
- Approximately 221,000 miles of distribution lines that deliver electricity to 5.5 million customers.
- Approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the eastern United States.
- Approximately 22,000 MWs of regulated owned generating capacity and approximately 4,900 MWs of regulated PPA capacity in 3 RTOs as of December 31, 2019, 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, 2019 decreased by 0.8% from the year ended December 31, 2018. AEP's 2019 industrial sales volumes decreased 1.9% compared to 2018. The decline in industrial sales was spread across most operating companies and many industries. Weather-normalized residential sales decreased 0.1% despite a 0.3% growth in customer counts. Weather-normalized commercial sales decreased by 0.4% in 2019 compared to 2018.

In 2020, AEP anticipates weather-normalized retail sales volumes will increase by 0.5%. The industrial class is expected to increase by 3.2% in 2020, while weather-normalized residential sales volumes are projected to decrease by 1.4%. Weather-normalized commercial sales volumes are projected to decrease by 0.4%.

Percentage Change in Sales Volume



(a) Percentage change for the year ended December 31, 2019 as compared to the year ended December 31, 2018.
(b) Forecasted percentage change for the year ended December 31, 2020 compared to the year ended December 31, 2019.

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. AEP is currently involved in the following key proceedings. See Note 4 - Rate Matters for additional information.

- *2019 Texas Base Rate Case* - In May 2019, AEP Texas filed a request with the PUCT for a $56 million annual increase in rates based upon a proposed 10.5% return on common equity. In November 2019, ALJs issued a Proposal for Decision recommending a $60 million annual rate reduction based upon a 9.4% return on common equity. The ALJs recommended disallowances that could potentially result in write-offs of $84 million related to capital incentives and $5 million related to other plant additions. Additionally, the ALJs recommended that AEP Texas should be required to file an application for a separate proceeding to determine if any refunds are required associated with any disallowances on distribution or transmission capital investments. In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity. The agreement provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The agreement includes disallowances of $23 million related to capital investments recorded through 2018 and $4 million related to rate case expenses. In addition, AEP Texas will refund: (a) $77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) $31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) $30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. As a result of the stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million in December 2019 related to capital investments, which included $10 million of current year investments, (b) recorded a $30 million provision for refund for revenues previously collected through rates and (c) wrote-off $4 million of rate case expenses. The PUCT is expected to issue an order in the first quarter of 2020.

- *2019 Indiana Base Rate Case* - In May 2019, I&M filed a request with the IURC for a $172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and is based upon a proposed 10.5% return on common equity. In August 2019, certain intervenors filed testimony that includes recommended disallowances that could potentially result in write-offs of $41 million related to the remaining book value of existing Indiana jurisdictional meters if I&M is approved to deploy Automated Metering Infrastructure meters and $11 million associated with certain Cook Plant study costs. The IURC is expected to issue an order on this case in the first quarter of 2020.

- *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 in excess of 70 basis points above APCo's Virginia SCC authorized ROE would be refunded to customers. Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets in December 2019. This expense is included in Asset Impairments and Other Related Charges on the statements of income. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period. Inclusive of the $93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo estimates its Virginia earnings for the triennial period to be below the authorized ROE range.

- *2020 Increase in West Virginia Retail Rates for WPCo 17.5% Merchant Share of Mitchell Plant* - In 2015, the WVPSC approved a settlement agreement in which 82.5% of the West Virginia jurisdictional costs associated with WPCo's acquired interest were prospectively reflected in retail rates with the remaining 17.5% of costs associated with the acquired interest to be included in rates starting January 2020. APCo and WPCo file joint retail rates in West Virginia. In June 2019, APCo and WPCo filed with the WVPSC to increase each company's retail rates through a surcharge to reflect the recovery of WPCo's remaining 17.5% interest in the Mitchell Plant. In December 2019, the WVPSC issued an order approving a stipulation and settlement agreement that will allow APCo and WPCo to recover the remaining 17.5% West Virginia share of costs related to the Mitchell Plant and increase pretax earnings on a combined company basis by approximately $21 million annually beginning January 1, 2020.

- *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 January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In May 2019, various intervenors filed replies to the petition. In July 2019, SWEPCo filed its response to these replies. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court. As of December 31, 2019, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. SWEPCo's Texas jurisdictional share of the Turk Plant investment is approximately 33%.

- In July 2019, clean energy legislation which offers incentives for power-generating facilities with zero or reduced carbon emissions was signed into law by the Ohio Governor. The clean energy legislation phases out current energy efficiency including lost shared savings revenues of $26 million annually and renewable mandates no later than 2020 and after 2026, respectively. The bill provides for the recovery of existing renewable energy contracts on a bypassable basis through 2032. The clean energy legislation also includes a provision for recovery of OVEC costs through 2030 which will be allocated to all electric distribution utilities on a non-bypassable basis. OPCo's Inter-Company Power Agreement for OVEC terminates in June 2040. To the extent that OPCo is unable to recover the costs of renewable energy contracts on a bypassable basis by the end of 2032, recover costs of OVEC after 2030 or fully recover energy efficiency costs through 2020 it could reduce future net income and cash flows and impact financial condition.

Utility Rates and Rate Proceedings

The Registrants file rate cases with their regulatory commissions in order to establish fair and appropriate 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 2019. 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
APCo	West Virginia	$ 35.8	9.75%	March 2019
WPCo	West Virginia	8.4	9.75%	March 2019
PSO	Oklahoma	46.0	9.4%	April 2019
SWEPCo	Arkansas	52.8	9.45%	January 2020
I&M	Michigan	36.4	9.86%	February 2020

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
			(in millions)		
AEP Texas (a)	Texas	May 2019	$ 56.0	10.5%	9% - 9.35%
I&M	Indiana	May 2019	172.0	10.5%	9% - 9.73%

(a) In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT that includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity. See "2019 Texas Base Rate Case" section of Note 4 for additional information.

Dolet Hills Power Station and Related Fuel Operations

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo's settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. Management also continues to monitor the economic viability of the Dolet Hills Power Station and DHLC mining operations, which may result in a decision to seek permission from appropriate regulatory agencies to discontinue operations earlier than 2026.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $157 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of December 31, 2019, DHLC has unbilled fixed costs of $106 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of December 31, 2019, Oxbow has unbilled fixed costs of $22 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

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

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.

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. AEP paid $580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $404 million as of the acquisition date (which includes $364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of $135 million. The wind generation portfolio includes seven wind farms with long-term PPAs for 100% of their energy production. Five of the wind farms are jointly-owned with BP Wind Energy and two wind farms are consolidated by AEP and are tax equity partnerships with nonaffiliated noncontrolling interests. See "Acquisitions" section of Note 7 for additional information.

In July 2019, AEP acquired a 75% interest, or 227 MWs, in Santa Rita East for approximately $356 million. The project is located in west Texas and was placed in-service in July 2019. Long-term virtual power purchase agreements are in place with nonaffiliates for the project's generation. See "Acquisitions" section of Note 7 for additional information.

As of December 31, 2019, subsidiaries within AEP's Generation & Marketing segment had approximately 1,421 MWs of contracted renewable generation projects in-service. In addition, as of December 31, 2019, these subsidiaries had approximately 156 MWs of renewable generation projects under construction with total estimated capital costs of $229 million related to these projects.

Regulated Renewable 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. In November 2019, PUCO denied OPCo's application for a resource planning need finding. In December 2019, OPCo filed an Application for Rehearing, which was also denied.

In July 2019, PSO and SWEPCo submitted filings before their respective commissions for the approval to acquire the North Central Wind Energy Facilities, comprised of three Oklahoma wind facilities totaling 1,485 MWs, on a fixed cost turn-key basis at completion. Subject to regulatory approval, PSO will own 45.5% and SWEPCo will own 54.5% of the project, which will cost approximately $2 billion. Two wind facilities, totaling 1,286 MWs, would qualify for 80% of the federal PTC with year-end 2021 in-service dates. The third wind facility (199 MWs) would qualify for 100% of the PTC with a year-end 2020 in-service date. The acquisition can be scaled, subject to commercial limitation, to align with individual state resource needs and approvals. In December 2019, PSO reached a joint stipulation and settlement agreement with the OCC, Oklahoma Attorney General's office and customer groups. In January 2020, SWEPCo reached a joint settlement agreement with the APSC, Arkansas Attorney General's office and Walmart, Inc. SWEPCo continues to work through the regulatory process in Texas and Louisiana. Hearings are scheduled for the first quarter of 2020. PSO and SWEPCo are seeking regulatory approvals by July 2020.

Federal Tax Reform

Based on current regulatory orders received, management anticipates amortization of $249 million of Excess ADIT in 2020 ($68 million of Excess ADIT subject to normalization requirements and $181 million of Excess ADIT that is not subject to normalization requirements). Customer usage or new regulatory orders could result in changes to these estimates. Management anticipates amortizing the following ranges of Excess ADIT that is not subject to normalization requirements over the next five years:

Annual Amortization of Unamortized Balance as of December 31, 2019

Year	Range (in millions)
2020	$ 165.0 - $ 196.0
2021	102.0 - 134.0
2022	75.0 - 105.0
2023	67.0 - 98.0
2024	34.0 - 65.0

Racine

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017. Due to a significant increase in estimated costs to complete the reconstruction project, AEP recorded impairments in 2017 and 2018. See Note 7 - Acquisitions, Dispositions and Impairments for additional information. Reconstruction activities at Racine are currently estimated to be completed in the first half of 2020. 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 book value once complete. Future revisions in cost estimates or delays in completion 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 (650 MW net maximum capacity) 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/477 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, 2019, 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.

FERC Transmission ROE Methodology

In November 2019, the FERC issued Opinion No. 569, which adopted a revised methodology for determining whether an existing base ROE is just and reasonable under Federal Power Act and determined the base ROE for MISO's transmission-owning members should be reduced to 9.88% (10.38% inclusive of RTO incentive adder of 0.5%). The revised ROE methodology relies on two financial models, which include the discounted cash flow model and the capital asset pricing model, to establish a composite zone of reasonableness. In December 2019, AEP filed multiple requests for rehearing and participated in filing comments and requests for rehearing on behalf of transmission owners and industry organizations. Management believes FERC Opinion No. 569 reverses the expectation of a four-model framework proposed by FERC in 2018 and vetted widely in FERC 2019 Notice of Inquiry regarding base ROE policy. Management does not believe this ruling will have a material impact on financial results for its MISO transmission-owning subsidiaries. In the second quarter of 2019, FERC approved settlement agreements establishing base ROEs of 9.85% (10.35% inclusive of RTO incentive adder of 0.5%) and 10% (10.5% inclusive of RTO incentive adder of 0.5%) for AEP's PJM and SPP transmission-owning subsidiaries, respectively. If FERC makes any changes to its ROE and incentive policies, they would be applied to AEP's PJM and SPP transmission owning subsidiaries on a prospective basis, and could affect 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 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 by the U.S. District Court for the Southern District of Ohio 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.

In 2017, 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.

Thereafter, 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. 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. The consent decree was modified based on an agreement among the parties in July 2019. The district court entered a stay that expired in February 2020. Settlement negotiations are continuing, and the parties filed a joint proposed case schedule in February 2020. See "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 cannot determine a range of potential losses that is reasonably possible of occurring.

Patent Infringement Complaint

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint seeks injunctive relief and damages. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and offering an opportunity to appeal those determinations. Management will continue to defend against the claims. 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 be made in response to existing and anticipated requirements to reduce emissions from fossil generation, 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 other parties, challenged some of the Federal EPA requirements. Management is 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 cannot 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 AEP System generating units. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2019, the AEP System had generating capacity of approximately 25,500 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 fossil generation. Based upon management estimates, AEP's future investment to meet these existing and proposed requirements ranges from approximately $500 million to $1 billion through 2026.

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) potential state rules that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) actual performance of the pollution control technologies installed, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors. In addition, management continues to evaluate the economic feasibility of environmental investments on 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, 2019.

Company	Plant Name and Unit	Generating Capacity (in MWs)	Amounts Pending Regulatory Approval (in millions)
APCo (a)	Kanawha River Plant	400	$ 14.1
APCo (b)	Clinch River Plant	705	25.5
APCo (a)	Sporn Plant, Units 1 and 3	300	2.0
APCo (a)	Glen Lyn Plant	335	3.5
SWEPCo (c)	Welsh Plant, Unit 2	528	35.5
Total		2,268	$ 80.6

(a) Remaining amounts pending regulatory approval represent the FERC and the West Virginia jurisdictional share. Management expensed the Virginia jurisdictional share in December 2019. See "Virginia Legislation Affecting Earnings Reviews" section of Note 4 for additional information.
(b) 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, Units 1 and 2 began operations as natural gas units in 2016.
(c) Remaining amount pending regulatory approval represents the FERC and Louisiana jurisdictional share. The APSC issued an order in December 2019 approving the recovery of the $15 million Arkansas jurisdictional share. See "2019 Arkansas Base Rate Case" section of Note 4 for additional information.

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.

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 2017, AEP filed a motion with the district court 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 Selective Catalytic Reduction technology at Rockport Plant, Unit 2 until June 2020.

In May 2019, the parties filed a proposed order to modify the consent decree. The proposed order requires AEP to enhance the dry sorbent injection system on both units at the Rockport Plant by the end of 2020, and meet 30-day rolling average emission rates for SO_2 and NO_x at the combined stack for the Rockport Plant beginning in 2021. Total SO_2 emissions from the Rockport Plant are limited to 10,000 tons per year beginning in 2021 and reduce to 5,000 tons per year when Rockport Plant, Unit 1 retires in 2028. The proposed modification was approved by the district court and became effective in July 2019. As part of the modification to the consent decree, I&M agreed to provide an additional $7.5 million to citizens' groups and the states for environmental mitigation projects. As joint owners in the Rockport Plant, the $7.5 million payment was shared between AEGCo and I&M based on the joint ownership agreement.

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 and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil generation under Section 111 of the CAA. 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 PM in 2012 and ozone in 2015. The Federal EPA is currently reviewing both of these standards. The existing standards for NO_2 and SO_2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of these standards is underway.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA 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. Challenges to the 2015 ozone standard and the Federal EPA's determination that CSAPR satisfies certain states' interstate transport obligations were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In August 2019, the court upheld the 2015 primary ozone standard, but remanded the secondary welfare-based standard for further review. The court vacated the Federal EPA's determination that CSAPR fulfilled the states' interstate transport obligations, because the Federal EPA's modeling analysis did not demonstrate that all significant contributions would be eliminated by the attainment deadlines for downwind states. Any further changes will require additional rulemaking. 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 FIPs. In 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

The Federal EPA initially disapproved portions of the Arkansas regional haze SIP, but has approved a revised SIP and all of SWEPCo's affected units are in compliance with the relevant requirements.

The Federal EPA also disapproved portions of the Texas regional haze SIP. In 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. A challenge to the FIP was filed in the U.S. Court of Appeals for the Fifth Circuit and the case is pending the Federal EPA's reconsideration of the final rule. In August 2018, the Federal EPA proposed to affirm its 2017 FIP approval. In November 2019, in response to comment, the Federal EPA proposed revisions to the intrastate trading program. Management supports the intrastate trading program as a compliance alternative to source-specific controls.

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 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.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 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 2016, the Federal EPA issued a final rule, the CSAPR Update, to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The CSAPR Update significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. In 2019, the appeals court remanded the CSAPR Update to the Federal EPA because it determined the Federal EPA had not properly considered the attainment dates for downwind areas in establishing its partial remedy, and should have considered whether there were available measures to control emissions from sources other than generating units. Any further changes to the CSAPR rule will require additional rulemaking.

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 for controlling emissions of organic HAPs and dioxin/furans, with compliance 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. Various intervenors filed petitions for further review in the U.S. Supreme Court.

In 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. In 2016, 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. In 2018, the Federal EPA released a revised 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. Therefore, the Federal EPA proposed to retain the current MATS standards without change.

Climate Change, CO_2 Regulation and Energy Policy

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

In 2016, the U.S. Supreme Court issued a stay of the final CPP, including all of the deadlines for submission of initial or final state plans 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 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 pending reconsideration. In September 2019, following the Federal EPA's repeal of the CPP and promulgation of a replacement rule, the Court of Appeals for the District of Columbia Circuit dismissed the challenges.

In July 2019, the Federal EPA finalized the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE establishes a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. The final rule applies to generating units that commenced construction prior to January 2014, generate greater than 25 MWs, have a baseload rating above 250 MMBtu per hour and burn coal for more than 10% of the annual average heat input over the preceding three calendar years, with certain exceptions. States must establish standards of performance for each affected facility in terms of pounds of CO_2 emitted per MWh, based on certain heat rate improvement measures and the degree of emission reduction achievable through each applicable measure, together with consideration of certain site-specific factors and the unit's remaining useful life. State plans are required to be submitted in 2022, and the Federal EPA has up to two years to review and approve a plan or disapprove it and adopt a federal plan. The final ACE rule has been challenged in the courts.

In 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 continues to actively monitor these rulemaking activities.

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet. AEP 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, purchasing renewable power and broadening AEP System's portfolio of energy efficiency programs.

In September 2019, 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 70% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is to surpass an 80% reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total estimated CO_2 emissions in 2019 were approximately 58 million metric tons, a 65% reduction from AEP's 2000 CO_2 emissions. AEP has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline. AEP's aspirational emissions goal is zero CO_2 emissions by 2050. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

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 (CCR) Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active CCR landfills and surface impoundments at operating electric utility or independent generation 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. In 2018, some of AEP's facilities were required to begin monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data, further studies to design and assess appropriate corrective measures have been undertaken at four facilities.

In a challenge to the final 2015 rule, the parties initially agreed to settle some of the issues. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit addressed or dismissed the remaining issues in its decision vacating and remanding certain provisions of the 2015 rule. 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.

Prior to the court's decision, the Federal EPA issued the July 2018 rule that modifies certain compliance deadlines and other requirements in the 2015 rule. 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 partial remand of the July 2018 rule. The court granted the Federal EPA's motion. In November 2019, the Federal EPA proposed revisions to implement the court's decision regarding the timing for closure of unlined surface impoundments along with impoundments not meeting the required distance from an aquifer. The comment period closed in January 2020. In December 2019, the Federal EPA proposed a federal permit program, implementing the Water Infrastructure Improvements for the Nation Act, that would apply in states that do not have an approved CCR program.

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 groundwaters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the CWA. Two cases were accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. The Federal EPA 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 groundwater, and issued an interpretive statement finding that discharges to groundwater are not subject to NPDES permitting requirements under the CWA. Management is unable to predict the impact of this guidance or the outcome of these cases 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. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units. In January 2020, a bill was introduced in Virginia to require removal of ash from units at the retired Glen Lyn Station, and provide for recovery of the costs incurred to remove the ash and close those units. If removal of ash is required without providing similar assurances of cost recovery in regulated jurisdictions, it would impose significant additional operating costs on AEP, which could lead to increased financing costs and liquidity needs. Other units in Virginia, Ohio, West Virginia, and Kentucky already have been closed in place in accordance with state law programs. 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 impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. Additional AEP facilities are reviewing these requirements as their wastewater discharge permits are renewed and making appropriate adjustments to their intake structures.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for generating facilities. The rule established 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 was challenged in the U.S. Court of Appeals for the Fifth Circuit. In 2017, the Federal EPA announced its intent to reconsider and potentially revise the standards for FGD wastewater and bottom ash transport water. The Federal EPA postponed the compliance deadlines for those wastewater categories to be no earlier than 2020, to allow for reconsideration. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater, and remanded them to the Federal EPA for reconsideration. In November 2019, the Federal EPA proposed revisions to the guidelines for existing generation facilities. The comment period ended in January 2020. Management is assessing technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

In 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. Various parties challenged the 2015 rule in different U.S. District Courts, which resulted in a patchwork of applicability of the 2015 rule and its predecessor. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers proposed a replacement rule. In September 2019, the Federal EPA repealed the 2015 rule. A final rule was issued in January 2020, which limits that scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, ditches, artificial ponds and waste treatment systems.

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

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

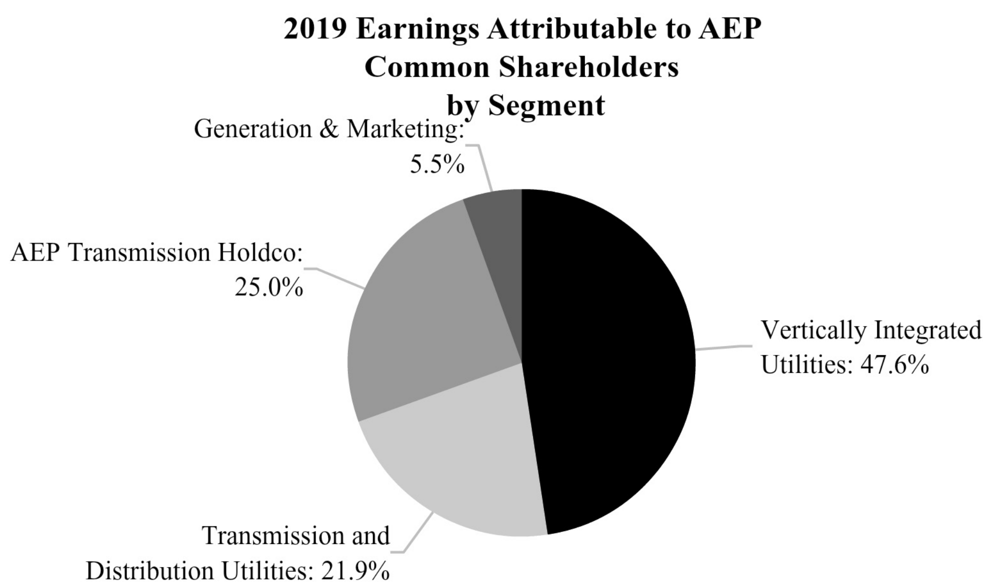
The remainder of AEP's activities are presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest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

The following discussion of AEP's 2019 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, these expenses 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.

A detailed discussion of AEP's 2018 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2018 Annual Report on Form 10-K filed with the SEC on February 21, 2019.

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

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Vertically Integrated Utilities	$ 982.0	$ 990.5	$ 790.5
Transmission and Distribution Utilities	451.0	527.4	636.4
AEP Transmission Holdco	516.3	369.9	352.1
Generation & Marketing	112.8	135.3	166.0
Corporate and Other	(141.0)	(99.3)	(32.4)
Earnings Attributable to AEP Common Shareholders	$ 1,921.1	$ 1,923.8	$ 1,912.6



Note: 2019 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment.

AEP CONSOLIDATED

2019 Compared to 2018

Earnings Attributable to AEP Common Shareholders decreased $3 million from $1.924 billion in 2018 to $1.921 billion in 2019 primarily due to:

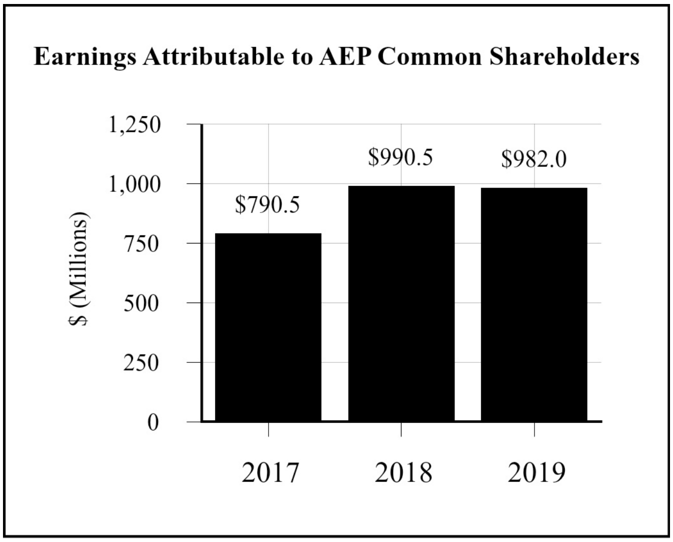
- A decrease in weather-related usage.
- An increase in asset impairments and other related charges.

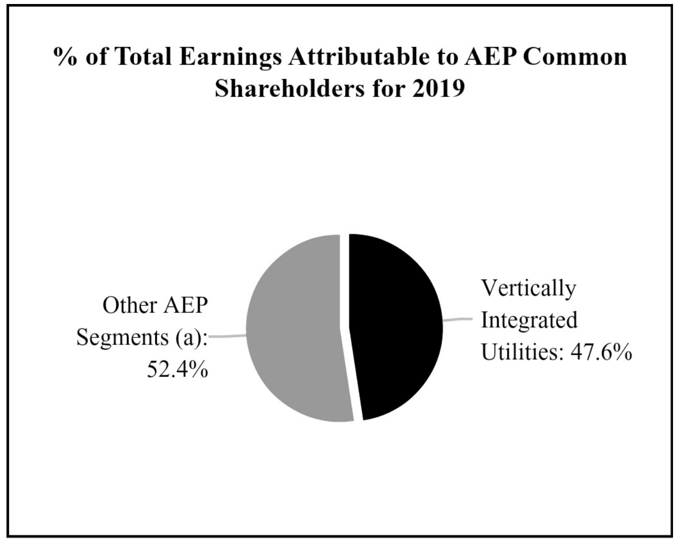
These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.
- An increase in transmission investment, which resulted in higher revenues and income.

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.

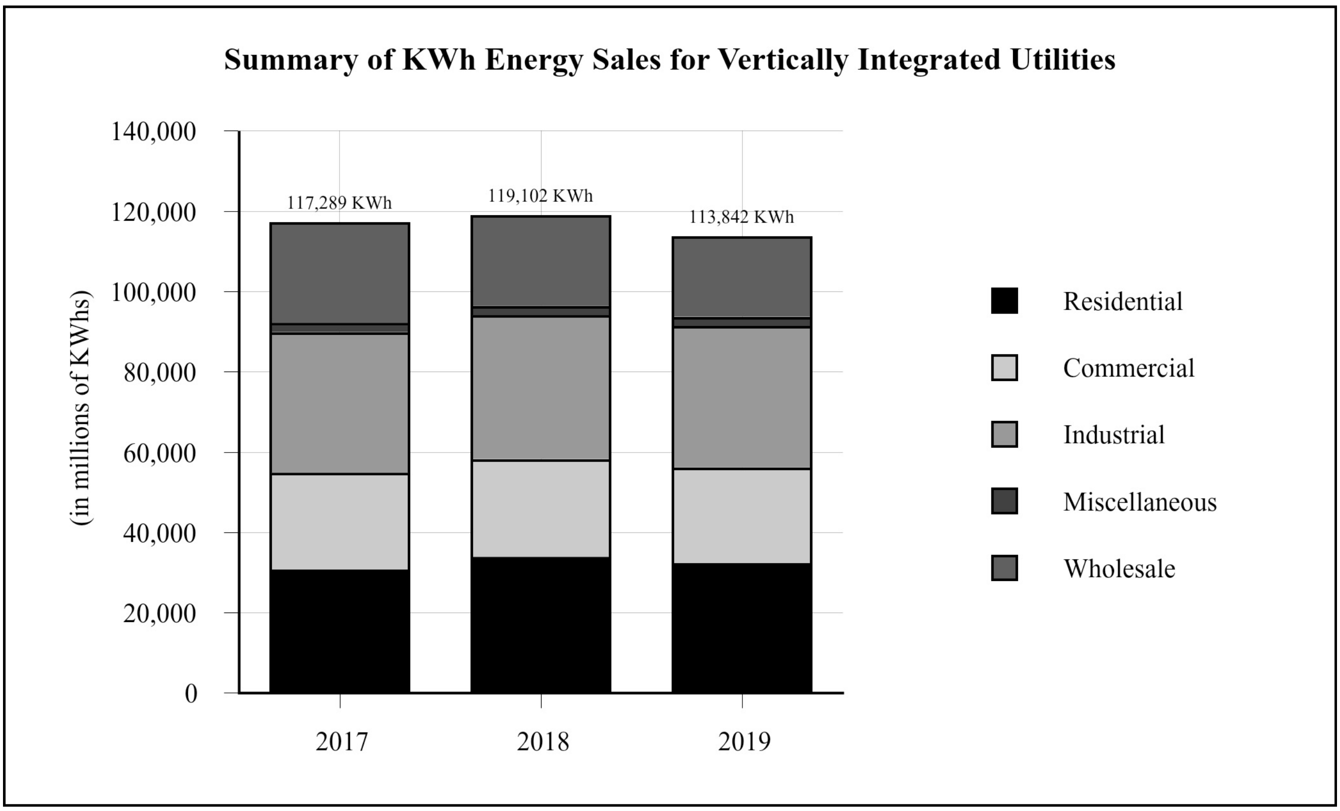
Vertically Integrated Utilities	2019	2018	2017
	Years Ended December 31, (in millions)		
Revenues	$ 9,367.1	$ 9,645.5	$ 9,192.0
Fuel and Purchased Electricity	3,103.1	3,488.9	3,142.7
Gross Margin	6,264.0	6,156.6	6,049.3
Other Operation and Maintenance	2,934.4	2,959.8	2,760.7
Asset Impairments and Other Related Charges	92.9	3.4	33.6
Depreciation and Amortization	1,447.0	1,316.2	1,142.5
Taxes Other Than Income Taxes	460.9	433.2	413.3
Operating Income	1,328.8	1,444.0	1,699.2
Other Income	6.1	17.0	22.0
Allowance for Equity Funds Used During Construction	50.7	35.4	28.0
Non-Service Cost Components of Net Periodic Benefit Cost	67.6	69.9	23.5
Interest Expense	(568.3)	(567.8)	(540.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	884.9	998.5	1,232.7
Income Tax Expense (Benefit)	(97.7)	5.7	425.6
Equity Earnings (Loss) of Unconsolidated Subsidiary	3.0	2.7	(3.8)
Net Income	985.6	995.5	803.3
Net Income Attributable to Noncontrolling Interests	3.6	5.0	12.8
Earnings Attributable to AEP Common Shareholders	$ 982.0	$ 990.5	$ 790.5

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	32,359	33,908	30,817
Commercial	23,839	24,452	24,052
Industrial	35,252	35,730	35,043
Miscellaneous	2,302	2,330	2,279
Total Retail (a)	93,752	96,420	92,191
Wholesale (b)	20,090	22,682	25,098
Total KWhs	113,842	119,102	117,289

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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

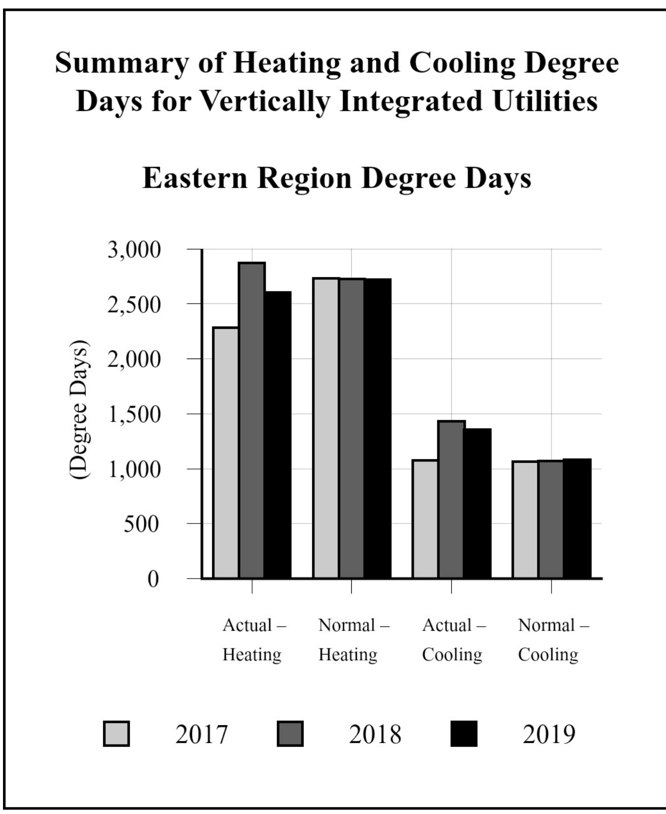


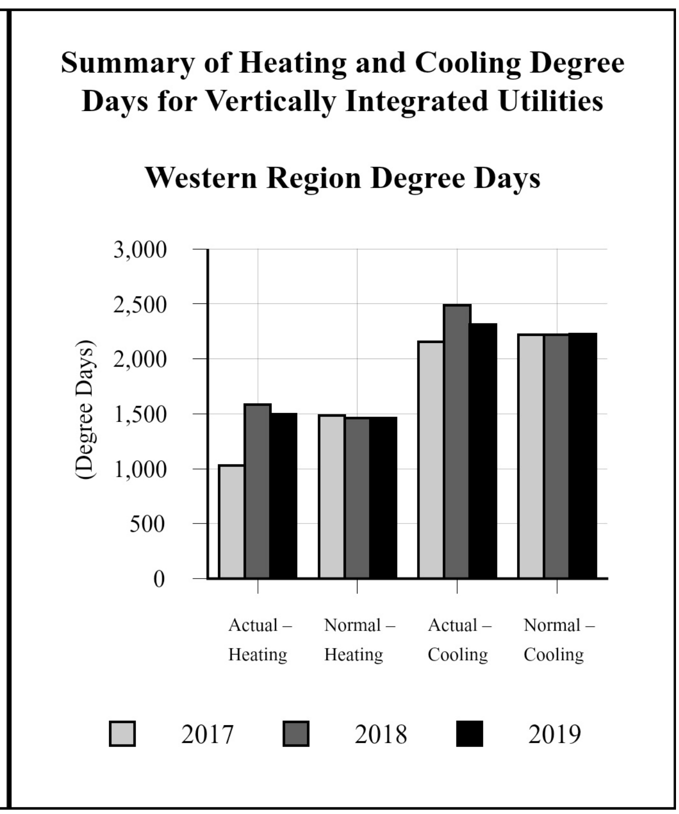
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,617	2,886	2,298
Normal – Heating (b)	2,732	2,738	2,746
Actual – Cooling (c)	1,369	1,443	1,088
Normal – Cooling (b)	1,092	1,083	1,078
Western Region			
Actual – Heating (a)	1,512	1,599	1,040
Normal – Heating (b)	1,473	1,475	1,494
Actual – Cooling (c)	2,328	2,502	2,164
Normal – Cooling (b)	2,240	2,230	2,229

(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.





2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2018	$ 990.5
Changes in Gross Margin:	
Retail Margins	134.1
Margins from Off-system Sales	(16.0)
Transmission Revenues	(14.0)
Other Revenues	3.3
Total Change in Gross Margin	107.4
Changes in Expenses and Other:	
Other Operation and Maintenance	25.4
Asset Impairments and Other Related Charges	(89.5)
Depreciation and Amortization	(130.8)
Taxes Other Than Income Taxes	(27.7)
Other Income	(10.9)
Allowance for Equity Funds Used During Construction	15.3
Non-Service Cost Components of Net Periodic Pension Cost	(2.3)
Interest Expense	(0.5)
Total Change in Expenses and Other	(221.0)
Income Tax Expense (Benefit)	103.4
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.3
Net Income Attributable to Noncontrolling Interests	1.4
Year Ended December 31, 2019	$ 982.0

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

- **Retail Margins** increased $134 million primarily due to the following:
  - A $91 million increase at APCo and WPCo due to a 2018 reduction in the deferred fuel under recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $30 million increase at APCo in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense at APCo in the prior year.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $112 million increase from rate proceedings at I&M, inclusive of a $24 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
    - A $46 million increase at PSO due to new base rates implemented in April 2019 and March 2018.
    - A $28 million increase at APCo and WPCo primarily due to revenue from rate riders in West Virginia. This increase was offset in other expense items below.
    - A $23 million increase related to rider revenues at I&M, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.
    - A $21 million increase at APCo and WPCo due to base rate increases in West Virginia implemented in March 2019.
    - A $20 million increase at SWEPCo primarily due to rider and base rate revenue increases in Louisiana and Texas. This increase was offset in other expense items below.
  - A $6 million decrease at I&M in fuel-related expenses due to timing of recovery for fuel and other variable production costs related to wholesale contracts.

These increases were partially offset by:

- A $120 million decrease due to customer refunds related to Tax Reform primarily at APCo, PSO and SWEPCo. This decrease was partially offset in Income Tax Expense (Benefit) below.
- A $102 million decrease in weather-related usage across all regions primarily in the residential and commercial classes.
- A $61 million decrease in weather-normalized retail margins primarily in the eastern region across all classes.

- **Margins from Off-system Sales** decreased $16 million primarily due to mid-year 2018 changes in the Indiana OSS sharing mechanism at I&M and lower volumes across the system.
- **Transmission Revenues** decreased $14 million primarily due to the following:
  - A $40 million decrease in the annual SPP formula rate true-up at SWEPCo.
  - A $19 million decrease at SWEPCo and PSO primarily due to a decrease in SPP Base Plan Funding Revenues.
  - A $5 million decrease due to a $14 million decrease at I&M, partially offset by a $9 million increase at KPCo and WPCo due to the 2018 PJM Transmission formula rate true-up.

  These decreases were partially offset by:
  - An $18 million increase in the net revenue requirement at APCo.
  - A $16 million increase at APCo due to 2018 PJM provisions for refunds.
  - A $16 million increase due to a provision for refund recorded at SWEPCo and PSO in 2018 related to certain transmission assets that management believes should not have been included in the SPP formula rate.

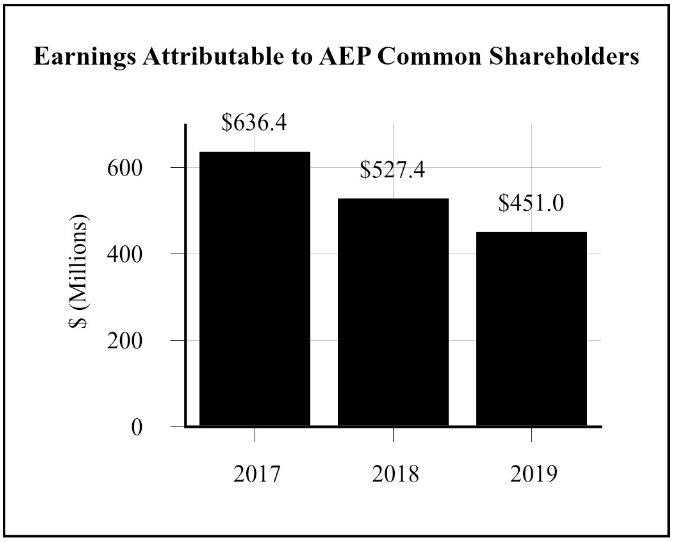
Expenses and Other and Income Tax Expense changed between years as follows:

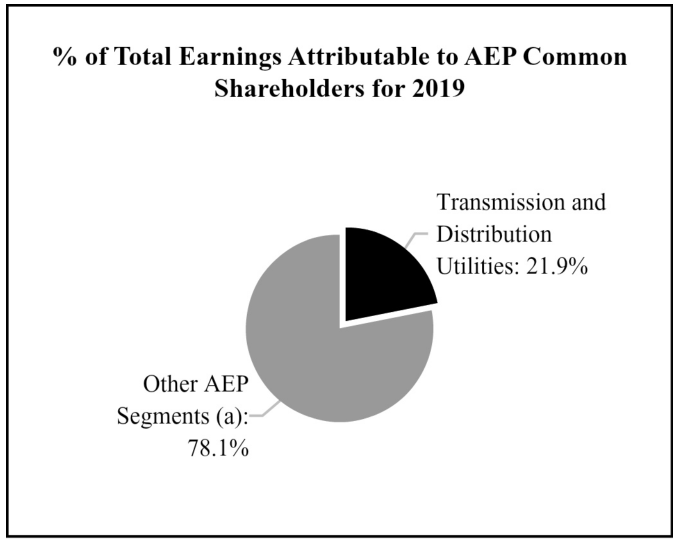
- **Other Operation and Maintenance** expenses decreased $25 million primarily due to the following:
  - A $73 million decrease in planned plant outage and maintenance expenses primarily at I&M, APCo, SWEPCo and KPCo.
  - A $58 million decrease due to SPP transmission services including the annual formula rate true-up.
  - A $40 million decrease due to Wind Catcher Project expenses incurred in 2018 at SWEPCo and PSO.
  - A $40 million decrease at APCo and WPCo due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement. This decrease is partially offset in Retail Margins above and Income Tax Expense (Benefit) below.
  - A $25 million decrease in recoverable expenses primarily associated with Energy Efficiency/Demand Response and storm-related expenses fully recovered in rate riders/trackers within Gross Margin above.
  - A $10 million decrease in expense at APCo due to lower current year amortization of certain regulatory assets that were extinguished in August 2018 as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $10 million decrease in estimated expense for claims related to asbestos exposure.

  These decreases were partially offset by:
  - A $131 million increase due to PJM transmission services including the annual formula rate true-up.
  - A $31 million increase in charitable contributions, primarily to the AEP Foundation.
  - A $25 million increase in employee-related expenses.
  - A $15 million increase at APCo and WPCo due to 2019 contributions to benefit low income West Virginia residential customers as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - An $8 million increase due to the modification of the NSR consent decree impacting I&M and AEGCo.
  - A $7 million increase due to North Central Wind Energy Facilities expenses at SWEPCo and PSO.
  - A $4 million increase due to the disallowance of previously recorded capital incentives at SWEPCo as a result of the December 2018 APSC final order.
  - A $4 million increase in accounts receivable factoring expense primarily at I&M and SWEPCo.
- **Asset Impairments and Other Related Charges** increased $90 million primarily due to a pretax expense recorded in 2019 related to previously retired coal-fired assets.
- **Depreciation and Amortization** expenses increased $131 million primarily due to a higher depreciable base and increased depreciation rates approved at APCo, I&M, PSO and SWEPCo.

- **Taxes Other Than Income Taxes** increased $28 million primarily due to the following:
  - A $15 million increase in property taxes driven by an increase in utility plant.
  - A $13 million increase in West Virginia business and occupational taxes at APCo and WPCo.
- **Other Income** decreased $11 million primarily due the following:
  - A $6 million decrease in carrying charges on certain riders at I&M.
  - A $4 million decrease in affiliated interest income at SWEPCo and I&M due to lower Utility Money Pool investment balances.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to the following:
  - A $10 million increase primarily due to various increases in equity rates at I&M, APCo and PSO and increased projects at I&M.
  - A $3 million increase due to recent FERC audit findings.
  - A $2 million increase due to the FERC's approval of a settlement agreement.
- **Income Tax Expense** decreased $103 million primarily due to additional amortization of Excess ADIT not subject to normalization requirements as a result of finalized rate orders in 2019, a decrease in pretax book income and a decrease in state tax expense. The amortization of Excess ADIT is partially offset in Gross Margin and Other Operation and Maintenance expenses above.

TRANSMISSION AND DISTRIBUTION UTILITIES





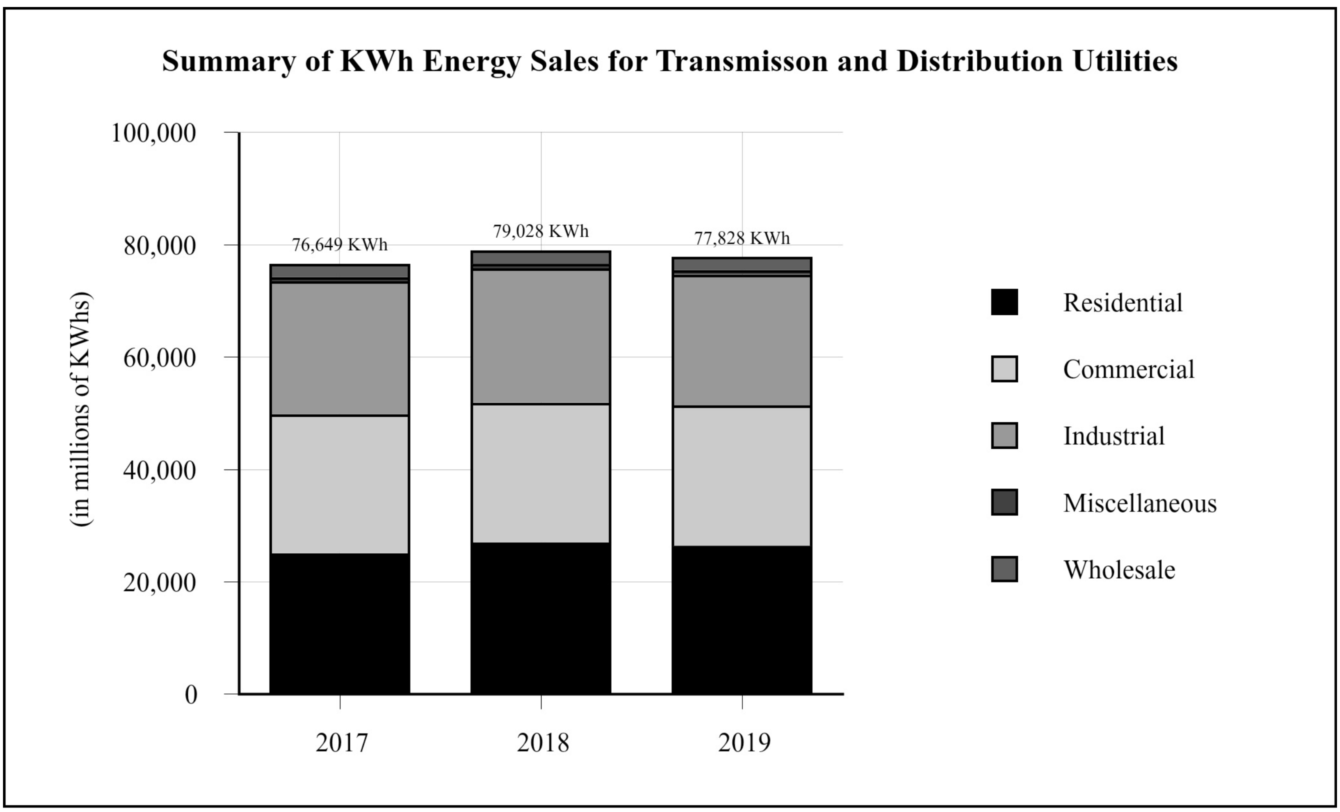
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

	Years Ended December 31,		
Transmission and Distribution Utilities	**2019**	**2018**	**2017**
		(in millions)	
Revenues	$ 4,482.5	$ 4,653.1	$ 4,419.3
Purchased Electricity	794.3	858.3	835.3
Amortization of Generation Deferrals	65.3	223.9	229.2
Gross Margin	3,622.9	3,570.9	3,354.8
Other Operation and Maintenance	1,628.1	1,541.7	1,199.3
Asset Impairments and Other Related Charges	32.5	—	—
Depreciation and Amortization	789.5	734.1	667.5
Taxes Other Than Income Taxes	575.0	545.3	513.7
Operating Income	597.8	749.8	974.3
Interest and Investment Income	6.6	4.2	7.7
Carrying Costs Income	1.0	1.7	3.6
Allowance for Equity Funds Used During Construction	33.4	29.9	13.2
Non-Service Cost Components of Net Periodic Benefit Cost	30.3	32.3	8.9
Interest Expense	(243.3)	(248.1)	(244.1)
Income Before Income Tax Expense (Benefit)	425.8	569.8	763.6
Income Tax Expense (Benefit)	(25.2)	42.4	127.2
Net Income	451.0	527.4	636.4
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 451.0	$ 527.4	$ 636.4

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	26,407	27,042	25,108
Commercial	25,018	24,877	24,724
Industrial	23,289	23,908	23,673
Miscellaneous	779	760	757
Total Retail (a)(b)	75,493	76,587	74,262
Wholesale (c)	2,335	2,441	2,387
Total KWhs	77,828	79,028	76,649

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Represents energy delivered to distribution customers.
(c) Primarily Ohio's contractually obligated purchases of OVEC power sold into PJM.

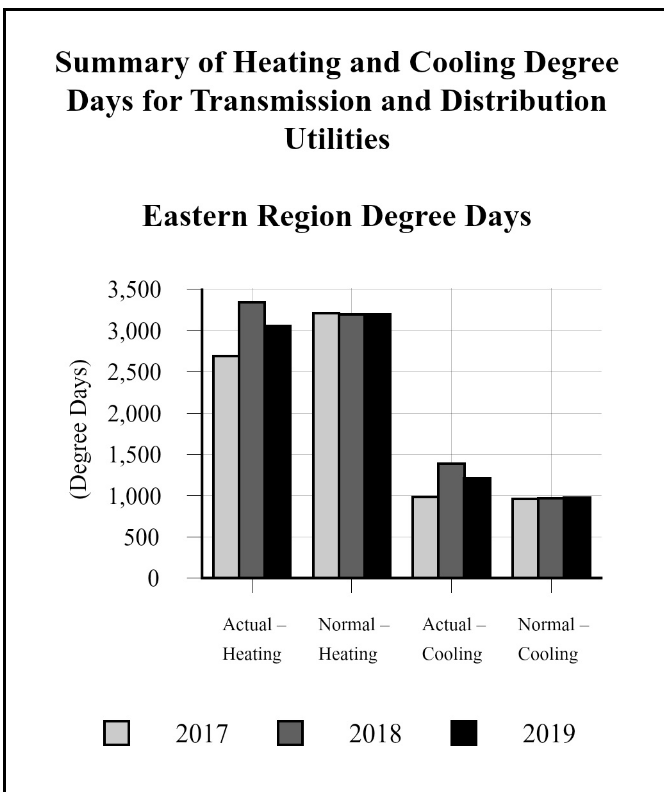


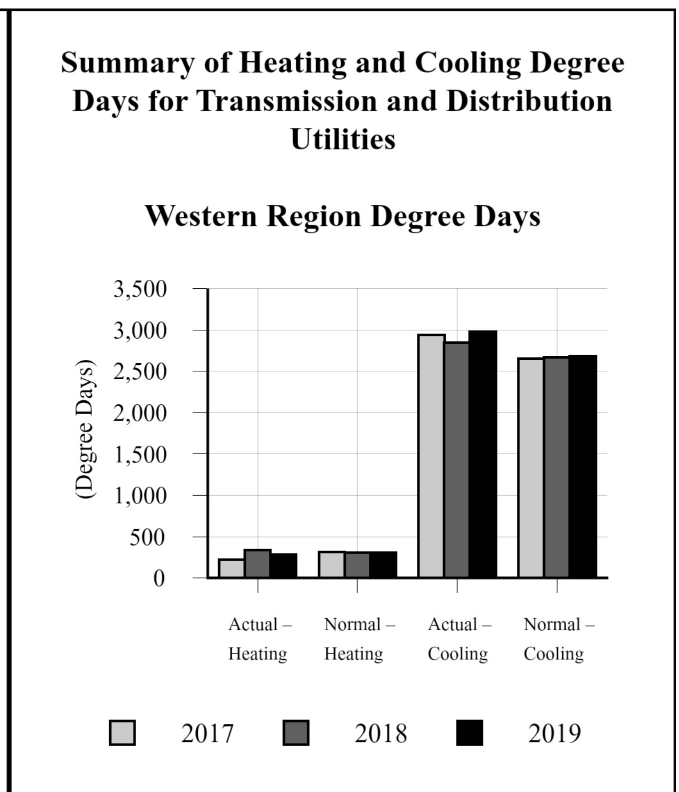
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two 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,		
	2019	**2018**	**2017**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,071	3,357	2,709
Normal – Heating (b)	3,208	3,215	3,225
Actual – Cooling (c)	1,224	1,402	1,002
Normal – Cooling (b)	992	980	974
Western Region			
Actual – Heating (a)	301	354	239
Normal – Heating (b)	322	325	330
Actual – Cooling (d)	2,989	2,861	2,950
Normal – Cooling (b)	2,699	2,688	2,669

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





2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2018	$	527.4
Changes in Gross Margin:		
Retail Margins		(65.2)
Margins from Off-system Sales		11.8
Transmission Revenues		85.6
Other Revenues		19.8
Total Change in Gross Margin		52.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(86.4)
Asset Impairments and Other Related Charges		(32.5)
Depreciation and Amortization		(55.4)
Taxes Other Than Income Taxes		(29.7)
Interest and Investment Income		2.4
Carrying Costs Income		(0.7)
Allowance for Equity Funds Used During Construction		3.5
Non-Service Cost Component of Net Periodic Benefit Cost		(2.0)
Interest Expense		4.8
Total Change in Expenses and Other		(196.0)
Income Tax Expense (Benefit)		67.6
Year Ended December 31, 2019	$	451.0

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

- **Retail Margins** decreased $65 million primarily due to the following:
  - A $103 million net decrease in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $30 million decrease due to a provision for refund in the 2019 Texas Base Rate Case.
  - A $25 million decrease in Ohio Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.
  - A $22 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $21 million net decrease in margin in Ohio for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
  - A $21 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $10 million decrease in weather-normalized margins primarily in the residential and commercial classes.

  These decreases were partially offset by:
  - A $58 million increase due to a reversal of a regulatory provision in Ohio.
  - A $41 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - A $33 million net increase due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense (Benefit) below.

- A $30 million increase due to the recovery of higher current year losses from a power contract with OVEC in Ohio. This increase was offset in Margins from Off-system Sales below.
- An $11 million increase in Ohio Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

- **Margins from Off-system Sales** increased $12 million primarily due to the following:
  - A $42 million increase due to higher affiliated PPA revenues in Texas. This increase was partially offset in Other Operation and Maintenance expenses below.

  This increase was partially offset by:
  - A $31 million decrease primarily due to higher current year losses from a power contract with OVEC as a result of the OVEC PPA rider in Ohio. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $86 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $20 million primarily due to the following:
  - An $11 million increase primarily due to securitization revenue. This increase was offset below in Depreciation and Amortization expenses and in Interest Expense.
  - A $7 million increase primarily due to distribution connection fees and pole attachment revenues in Ohio.

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

- **Other Operation and Maintenance** expenses increased $86 million primarily due to the following:
  - A $68 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - A $64 million increase in expense due to the partial amortization of the Texas Storm Cost Securitization regulatory asset as a result of the final PUCT order in the Texas Storm Cost Case. This increase was offset in Income Tax Expense (Benefit) below.
  - A $49 million increase in affiliated PPA expenses in Texas. This increase was offset in Margins from Off-system Sales above.
  - A $12 million increase due to a charitable contribution to the AEP Foundation.

  These increases were partially offset by:
  - A $117 million decrease in transmission expenses that were fully recovered in rate riders/trackers in Gross Margin above.
- **Asset Impairments and Other Related Charges** increased $33 million due to regulatory disallowances in the 2019 Texas Base Rate Case.
- **Depreciation and Amortization** expenses increased $55 million primarily due to the following:
  - A $68 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $17 million increase in securitization amortizations in Texas. This increase was offset in Other Revenues above and in Interest Expense below.
  - An $11 million increase due to lower deferred equity amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019.
  - A $6 million increase in depreciation expense related to the Oklaunion Power Station.

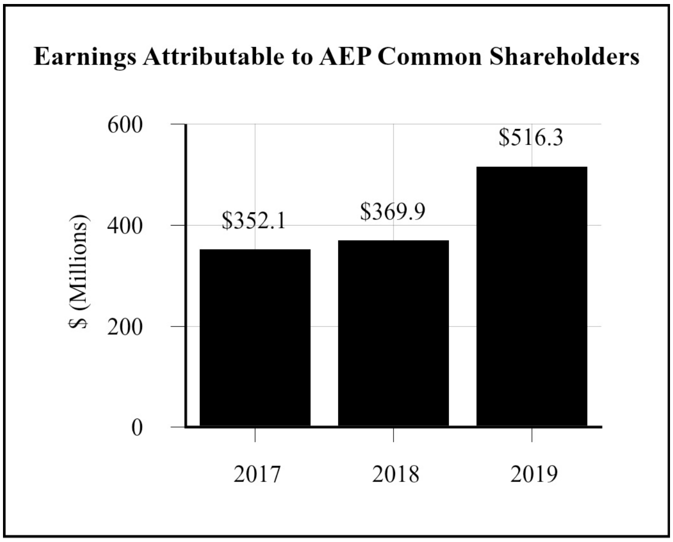
  These increases were partially offset by:
  - A $26 million decrease in Ohio recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - A $23 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $30 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to the following:
  - An $8 million increase in Ohio primarily due to adjustments that resulted from 2019 FERC audit findings.

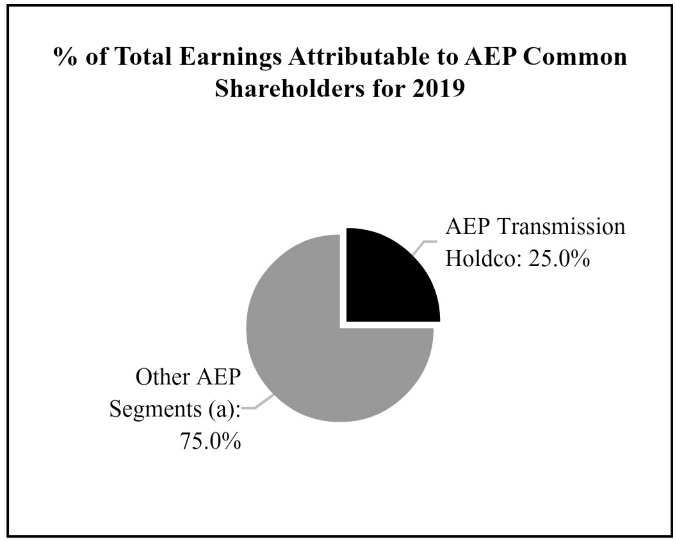
  This increase was partially offset by:
  - A $5 million decrease in the Equity component as a result of higher short-term debt balances, partially offset by increased transmission projects.

- **Interest Expense** decreased $5 million primarily due to the following:
  - A $21 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
  - An $11 million decrease in expense related to Securitization assets. This decrease was offset in Other Revenues and Depreciation and Amortization expenses above.

  These decreases were partially offset by:
  - A $22 million increase due to higher long-term debt balances.
  - A $2 million increase due to higher short-term debt balances.
- **Income Tax Expense (Benefit)** decreased $68 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019 and a decrease in pretax book income. This decrease was partially offset above in Retail Margins and Other Operation and Maintenance expenses.

AEP TRANSMISSION HOLDCO



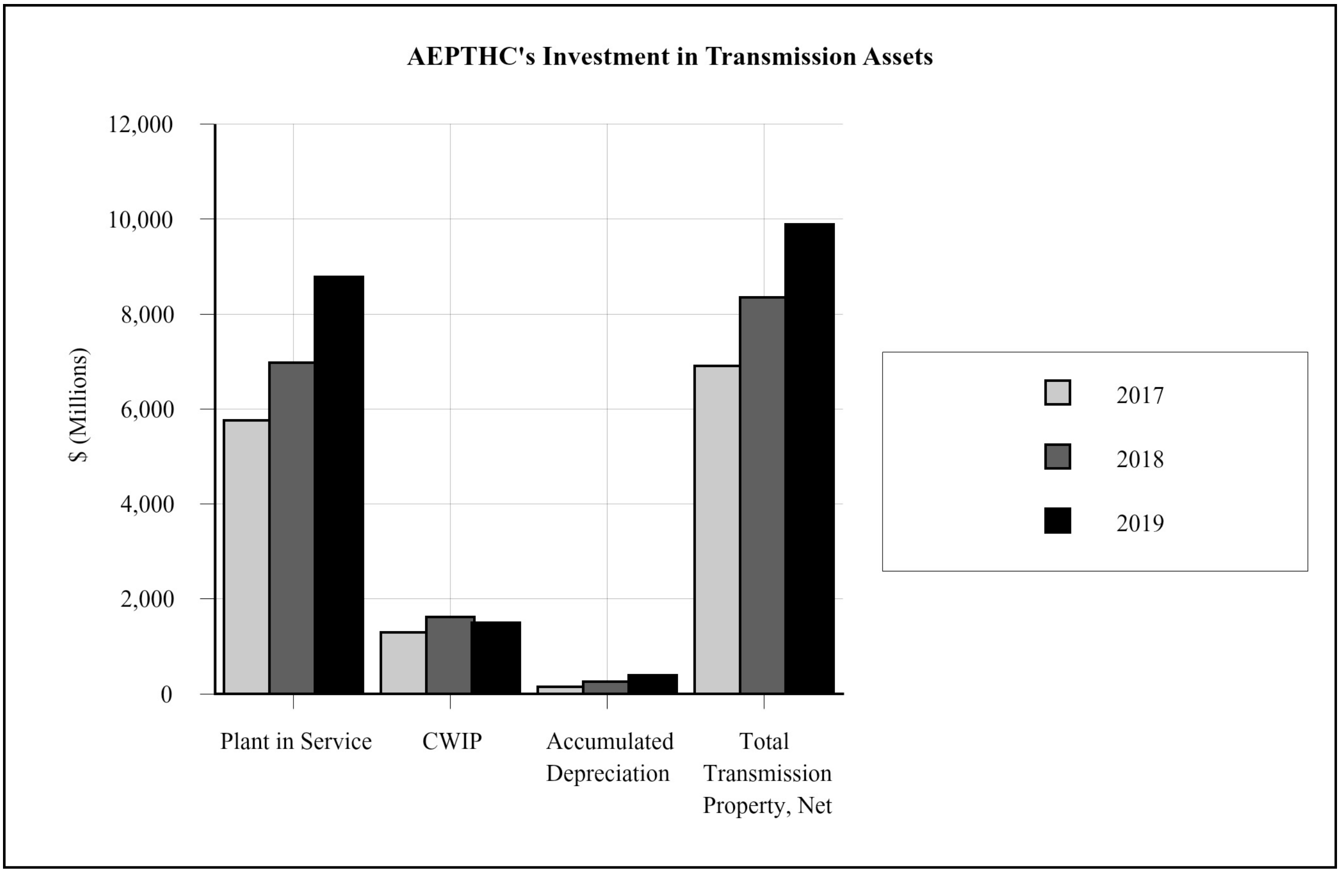


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

AEP Transmission Holdco	Years Ended December 31, 2019	2018	2017
		(in millions)	
Transmission Revenues	$ 1,073.2	$ 804.1	$ 766.7
Other Operation and Maintenance	119.0	105.6	74.7
Depreciation and Amortization	183.4	137.8	102.2
Taxes Other Than Income Taxes	174.4	142.3	114.0
Operating Income	596.4	418.4	475.8
Other Income	3.4	2.1	1.0
Allowance for Equity Funds Used During Construction	84.3	67.2	52.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.7	2.6	0.3
Interest Expense	(103.3)	(90.7)	(72.8)
Income Before Income Tax Expense and Equity Earnings	583.5	399.6	456.8
Income Tax Expense	136.2	95.3	189.8
Equity Earnings of Unconsolidated Subsidiary	72.8	68.7	88.6
Net Income	520.1	373.0	355.6
Net Income Attributable to Noncontrolling Interests	3.8	3.1	3.5
Earnings Attributable to AEP Common Shareholders	$ 516.3	$ 369.9	$ 352.1

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2019	December 31, 2018	December 31, 2017
		(in millions)	
Plant in Service	$ 8,812.2	$ 7,008.4	$ 5,784.6
Construction Work in Progress	1,521.8	1,651.1	1,325.6
Accumulated Depreciation and Amortization	418.9	282.8	176.6
Total Transmission Property, Net	$ 9,915.1	$ 8,376.7	$ 6,933.6



2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2018	$	369.9
Changes in Transmission Revenues:		
Transmission Revenues		269.1
Total Change in Transmission Revenues		269.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(13.4)
Depreciation and Amortization		(45.6)
Taxes Other Than Income Taxes		(32.1)
Other Income		1.3
Allowance for Equity Funds Used During Construction		17.1
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(12.6)
Total Change in Expenses and Other		(85.2)
Income Tax Expense		(40.9)
Equity Earnings of Unconsolidated Subsidiary		4.1
Net Income Attributable to Noncontrolling Interests		(0.7)
Year Ended December 31, 2019	$	516.3

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

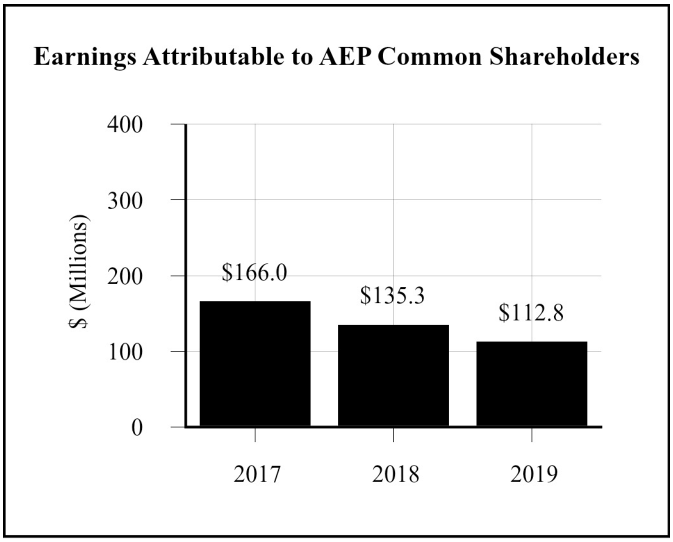
- **Transmission Revenues** increased $269 million primarily due to continued investment in transmission assets.

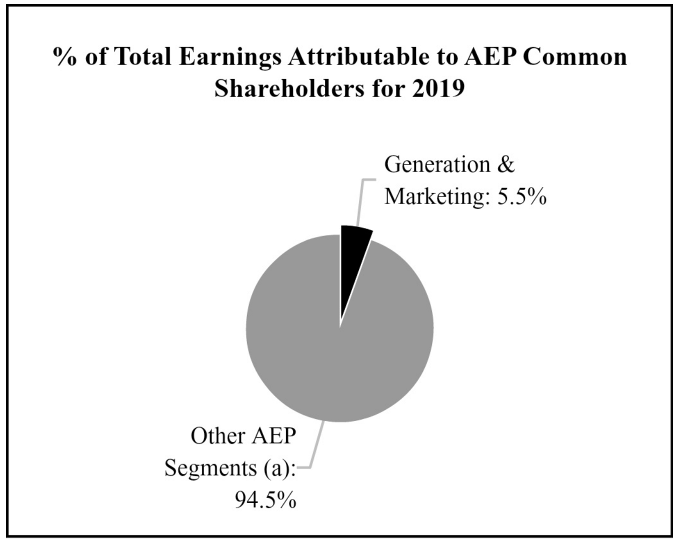
Expenses and Other, Income Tax Expense and Equity Earnings of Unconsolidated Subsidiaries changed between years as follows:

- **Other Operation and Maintenance** expenses increased $13 million primarily due to the following:
  - A $7 million increase due to a charitable contribution to the AEP Foundation.
  - A $6 million increase due to continued investment in transmission assets.
- **Depreciation and Amortization** expenses increased $46 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $32 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to the following:
  - An $18 million increase due to higher monthly CWIP balances.
  - A $12 million increase due to the FERC's approval of a settlement agreement.

  These increases were partially offset by:
  - A $13 million decrease due to recent FERC audit findings.
- **Interest Expense** increased $13 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $41 million primarily due to higher pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** increased $4 million primarily due to higher pretax equity earnings at ETT.

GENERATION & MARKETING



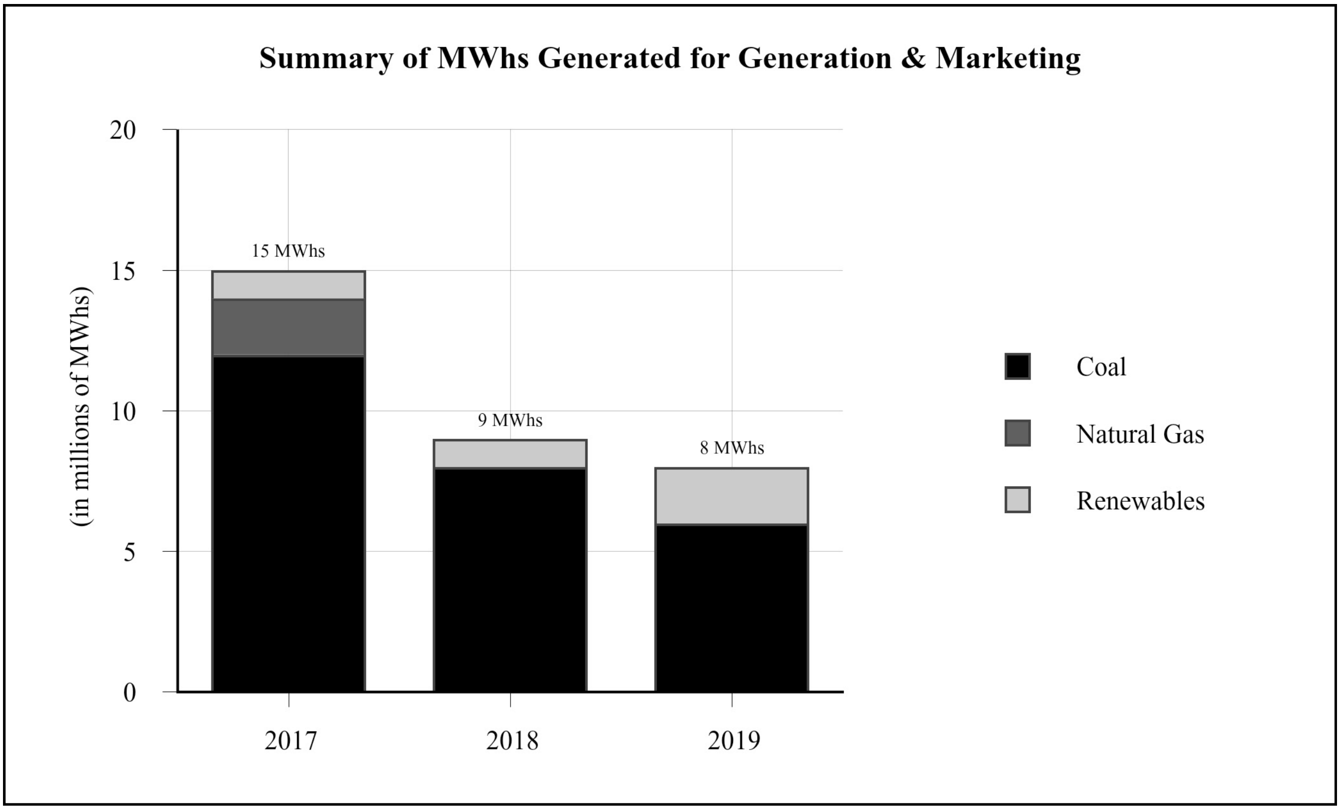


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Generation & Marketing	Years Ended December 31, 2019	2018	2017
		(in millions)	
Revenues	$ 1,857.6	$ 1,940.3	$ 1,875.1
Fuel, Purchased Electricity and Other	1,456.2	1,537.3	1,377.2
Gross Margin	401.4	403.0	497.9
Other Operation and Maintenance	223.8	229.3	279.5
Asset Impairments and Other Related Charges	31.0	47.7	53.5
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Depreciation and Amortization	69.5	41.0	24.2
Taxes Other Than Income Taxes	15.6	13.4	12.1
Operating Income	61.5	71.6	355.0
Interest and Investment Income	7.7	13.1	10.3
Non-Service Cost Components of Net Periodic Benefit Cost	14.9	15.2	8.9
Interest Expense	(30.0)	(14.9)	(18.5)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	54.1	85.0	355.7
Income Tax Expense (Benefit)	(53.8)	(49.2)	189.7
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(3.8)	0.5	—
Net Income	104.1	134.7	166.0
Net Loss Attributable to Noncontrolling Interests	(8.7)	(0.6)	—
Earnings Attributable to AEP Common Shareholders	$ 112.8	$ 135.3	$ 166.0

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2019	2018	2017
	(in millions of MWhs)		
Fuel Type:			
Coal	6	8	12
Natural Gas	—	—	2
Renewables	2	1	1
Total MWhs	8	9	15



2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2018	$	135.3
Changes in Gross Margin:		
Merchant Generation		(73.3)
Renewable Generation		31.9
Retail, Trading and Marketing		39.8
Total Change in Gross Margin		(1.6)
Changes in Expenses and Other:		
Other Operation and Maintenance		5.5
Asset Impairments and Other Related Charges		16.7
Depreciation and Amortization		(28.5)
Taxes Other Than Income Taxes		(2.2)
Interest and Investment Income		(5.4)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(15.1)
Total Change in Expenses and Other		(29.3)
Income Tax Expense (Benefit)		4.6
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(4.3)
Net Loss Attributable to Noncontrolling Interests		8.1
Year Ended December 31, 2019	$	112.8

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

- **Merchant Generation** decreased $73 million primarily due to the following:
  - A $42 million decrease due to reduced capacity and energy margins.
  - A $17 million decrease due to the retirement of the Stuart Plant in 2018.
  - A $14 million decrease due to the retirement of Conesville Units 5 and 6 in 2019.
- **Renewable Generation** increased $32 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.
- **Retail, Trading and Marketing** increased $40 million due to higher retail margins due to lower market costs and higher delivered volumes and higher marketing activity in 2019.

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

- **Other Operation and Maintenance** expenses decreased $6 million primarily due to the retirement of the Stuart Plant and Conesville Units 5 and 6 partially offset by expenses related to the Sempra Renewables LLC acquisition and increased investments in wind farms and renewable energy sources.
- **Asset Impairments and Other Related Charges** decreased $17 million primarily due to a $35 million decrease in impairment charges related to Racine partially offset by a $19 million increase in impairment charges related to the Conesville plant in 2019.
- **Depreciation and Amortization** expenses increased $29 million primarily due to a higher depreciable base from increased investments in renewable energy sources.

- **Interest Expense** increased $15 million primarily due to increased borrowing costs related to the Sempra Renewables LLC acquisition.
- **Income Tax Expense (Benefit)** increased $5 million primarily due to an increase in income and production tax credits related to the Sempra Renewables LLC and Santa Rita East acquisitions. This increase was partially offset by a decrease in parent savings in 2019.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $4 million primarily due to the Sempra Renewables LLC acquisition.
- **Net Loss Attributed to Noncontrolling Interests** increased $8 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

2019 Compared to 2018

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $99 million in 2018 to a loss of $141 million in 2019 primarily due to:

- A $71 million increase in interest expense as a result of increased debt outstanding.
- A $12 million increase in general corporate expenses.
- A $6 million increase in tax expense primarily due to the following:
  - A $23 million increase in state income tax expense related to unitary state filing requirements.
  - An $18 million increase related to the enactment of the Kentucky state tax legislation in the second quarter of 2018.
  - A $5 million increase due to the current year revaluation of AEP's state deferred tax liability as a result of the state income tax filing requirement in Kansas associated with the Sempra Renewables LLC acquisition.

  These increases were partially offset by:
  - A $43 million decrease due to a decrease in the allocation of the parent company loss benefit due to the tax sharing agreement.
- A $5 million write-off of an equity investment and related assets in 2019.

These items were partially offset by:

- A $20 million impairment of an equity investment and related assets in 2018.
- An $18 million increase in interest income from affiliates.
- A $16 million increase in interest income due to a higher return on investments held by EIS.

AEP SYSTEM INCOME TAXES

2019 Compared to 2018

Income Tax Expense decreased $128 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements as a result of finalized rate orders in 2019, an increase in income and production tax credits driven by the Sempra Renewables LLC and Santa Rita East acquisitions and a decrease in pretax book income.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2019		2018	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 26,725.5	54.1%	$ 23,346.7	52.7%
Short-term Debt	2,838.3	5.7	1,910.0	4.3
Total Debt	29,563.8	59.8	25,256.7	57.0
AEP Common Equity	19,632.2	39.6	19,028.4	42.9
Noncontrolling Interests	281.0	0.6	31.0	0.1
Total Debt and Equity Capitalization	$ 49,477.0	100.0%	$ 44,316.1	100.0%

AEP's ratio of debt-to-total capital increased from 57.0% to 59.8% as of December 31, 2018 and 2019, respectively, primarily due to an increase in debt to support distribution, transmission and renewable investment growth.

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, 2019, 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, leasing agreements, hybrid securities or common stock.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2019, available liquidity was $2.1 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	246.8	
Total Liquidity Sources	4,246.8	
Less: AEP Commercial Paper Outstanding	2,110.0	
Net Available Liquidity	$ 2,136.8	

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 2019 was $2.2 billion. The weighted-average interest rate for AEP's commercial paper during 2019 was 2.51%.

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 six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2019, was $207 million with maturities ranging from January 2020 to December 2020.

Financing Plan

As of December 31, 2019, AEP had $1.6 billion of long-term debt due within one year. This included $431 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 $392 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the 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 expires in July 2021.

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 agreement excludes securitization bonds and debt of AEP Credit. As of December 31, 2019, this contractually-defined percentage was 57.4%. 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.

Equity Units

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes due in 2024 and a forward equity purchase contract which settles after three years in 2022. The proceeds from this issuance were used to support AEP's overall capital expenditure plans including the recent acquisition of Sempra Renewables LLC. See Note 14 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.70 per share in January 2020. 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,		
	2019	2018	2017
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 444.1	$ 412.6	$ 403.5
Net Cash Flows from Operating Activities	4,270.1	5,223.2	4,270.4
Net Cash Flows Used for Investing Activities	(7,144.5)	(6,353.6)	(3,656.4)
Net Cash Flows from (Used for) Financing Activities	2,862.9	1,161.9	(604.9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(11.5)	31.5	9.1
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 432.6	$ 444.1	$ 412.6

Operating Activities

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Non-Cash Adjustments to Net Income (a)	2,685.7	2,400.0	2,822.6
Mark-to-Market of Risk Management Contracts	(29.2)	(66.4)	(23.3)
Pension Contributions to Qualified Plan Trust	—	—	(93.3)
Property Taxes	(73.8)	(59.1)	(29.5)
Deferred Fuel Over/Under Recovery, Net	85.2	189.7	84.4
Recovery of Ohio Capacity Costs, Net	34.1	67.7	83.2
Refund of Global Settlement	(16.5)	(5.5)	(98.2)
Change in Other Noncurrent Assets	(97.4)	119.8	(423.9)
Change in Other Noncurrent Liabilities	(116.1)	129.0	181.7
Change in Certain Components of Working Capital	(121.7)	516.7	(162.2)
Net Cash Flows from Operating Activities	$ 4,270.1	$ 5,223.2	$ 4,270.4

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Rockport Plant Unit 2 Operating Lease 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.

2019 Compared to 2018

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

- A $638 million decrease in cash from Changes in Certain Components of Working Capital. This decrease was primarily due to an increase in fuel, material and supplies balances as a result of mild winter weather, the addition of operating lease payments due to the adoption of ASU 2016-02, higher employee-related benefits and revenue refunds related to Tax Reform. These decreases were partially offset by timing of accounts receivables.
- A $245 million decrease in cash from Change in Other Noncurrent Liabilities primarily due to increases in revenue refunds related to Tax Reform and Ohio regulatory liabilities.
- A $217 million decrease in cash from Changes in Other Noncurrent Assets primarily due to a change in regulatory assets as a result of AEP subsidiaries with rider recovery mechanisms. See Note 4 - Rate Matters for additional information.
- A $105 million decrease in cash from Deferred Fuel Over/Under Recovery, Net primarily due to the full recovery of the Ohio Phase-in-Recovery Rider and prior year reduction of ENEC balances at APCo and WPCo as a result of the 2018 West Virginia Tax Reform Order, partially offset by net rate and weather fluctuations across jurisdictions. See Note 4 - Rate Matters for additional information.

These decreases in cash were partially offset by:

- A $274 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.

Investing Activities

	Years Ended December 31, 2019	2018	2017
		(in millions)	
Construction Expenditures	$ (6,051.4)	$ (6,310.9)	$ (5,691.3)
Acquisitions of Nuclear Fuel	(92.3)	(46.1)	(108.0)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(918.4)	—	—
Proceeds from Sale of Merchant Generation Assets	—	—	2,159.6
Other	(82.4)	3.4	(16.7)
Net Cash Flows Used for Investing Activities	$ (7,144.5)	$ (6,353.6)	$ (3,656.4)

2019 Compared to 2018

Net Cash Flows Used for Investing Activities increased by $791 million primarily due to the following:

- A $918 million increase due to the acquisition of Sempra Renewables LLC and Santa Rita East. The $918 million represents a cash payment of $936 million, net of cash and restricted cash acquired of $18 million. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.

This increase in the use of cash was partially offset by:

- A $260 million decrease in construction expenditures primarily due to decreases in Generation & Marketing.

Financing Activities

	Years Ended December 31, 2019	2018	2017
		(in millions)	
Issuance of Common Stock	$ 65.3	$ 73.6	$ 12.2
Issuance/Retirement of Debt, Net	4,244.1	2,435.1	691.8
Dividends Paid on Common Stock	(1,350.0)	(1,255.5)	(1,191.9)
Other	(96.5)	(91.3)	(117.0)
Net Cash Flows from (Used for) Financing Activities	$ 2,862.9	$ 1,161.9	$ (604.9)

2019 Compared to 2018

Net Cash Flows from Financing Activities increased by $1.7 billion primarily due to the following:

- A $1.6 billion increase in cash due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $657 million increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 14 - Financing Activities for additional information.

These increases in cash were partially offset by:

- A $409 million decrease in issuance of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2019:

AEP Common Stock:

- During 2019, AEP issued 924 thousand shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $65 million.

Debt:

- During 2019, AEP issued approximately $4.6 billion of long-term debt, including $2.7 billion of senior unsecured notes at interest rates ranging from 3.15% to 4.5%, $805 million of junior subordinated debenture note at interest rate of 3.4%, $771 million of pollution control bonds at interest rates ranging from 1.35% to 2.60%, and $375 million of other debt at various interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2019, AEP entered into interest rate derivatives with notional amounts totaling $125 million that were designated as cash flow hedges. As of December 31, 2019, AEP had a total notional amount of $125 million of interest rate derivatives designated as cash flow hedges. During 2019, settlements of AEP's interest rate derivatives designated as fair value hedges resulted in net cash paid of $1.5 million. As of December 31, 2019, AEP had a total notional amount of $500 million of outstanding interest rate derivatives designated as fair value hedges.

In 2020:

In January and February 2020, AEP Texas retired $111 million and $3 million, respectively, of Securitization Bonds.

In January and February 2020, I&M retired $8 million and $5 million, respectively, of Notes Payable related to DCC Fuel.

In January 2020, Transource Energy issued $4 million of variable rate Other Long-term Debt due in 2023.

In February 2020, APCo retired $12 million of Securitization Bonds.

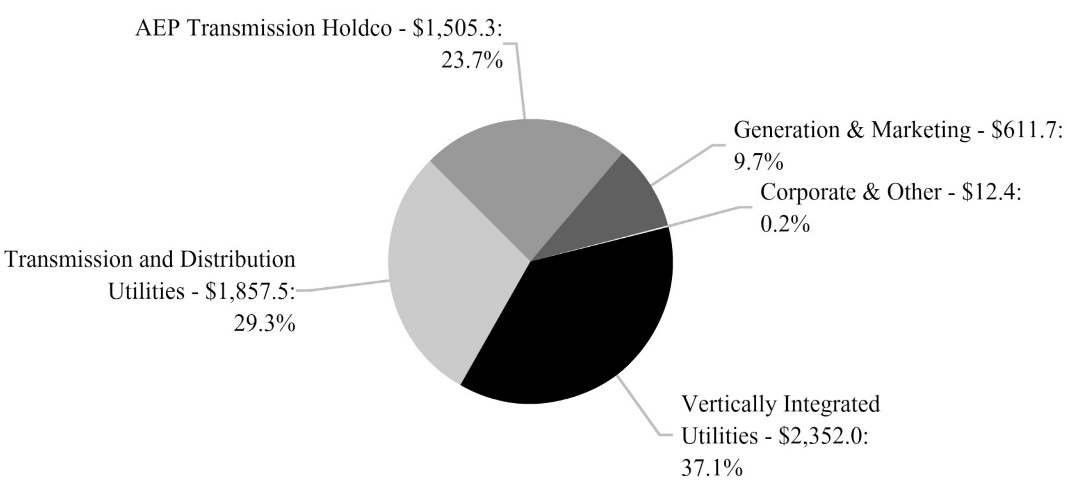
BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $6.3 billion of capital expenditures in 2020. For the four year period, 2021 through 2024, management forecasts capital expenditures of $26.6 billion. Capital expenditures related to North Central Wind Energy Facilities are excluded from these budgeted amounts. 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 2020 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2020 Budgeted Capital Expenditures					
Segment	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
Vertically Integrated Utilities	$ 165.1	$ 277.2	$ 701.0	$ 899.6	$ 309.1	$ 2,352.0
Transmission and Distribution Utilities	—	1.8	765.3	870.9	219.5	1,857.5
AEP Transmission Holdco	—	—	1,452.0	—	53.3	1,505.3
Generation & Marketing	11.0	571.8	—	—	28.9	611.7
Corporate and Other	—	—	—	—	12.4	12.4
Total	$ 176.1	$ 850.8	$ 2,918.3	$ 1,770.5	$ 623.2	$ 6,338.9

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

2020 Budgeted Capital Expenditures by Business Segment

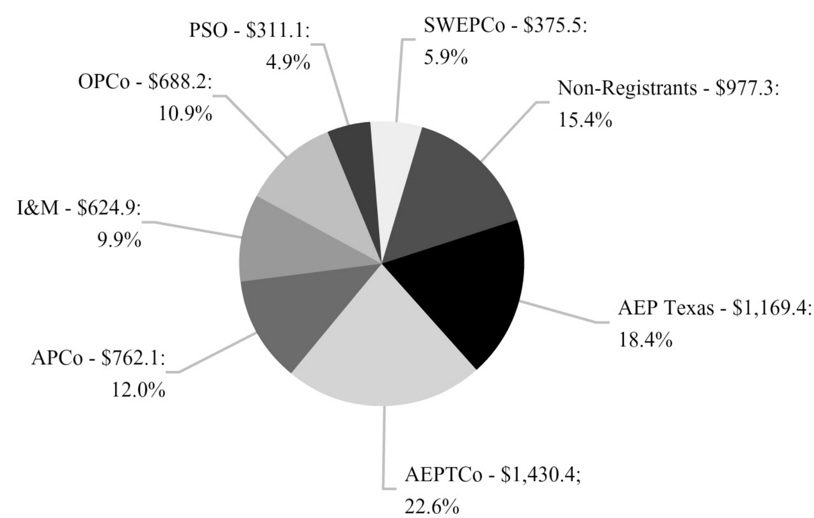


The 2020 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation related investments, as well as expenditures for compliance with environmental regulations as follows:

	2020 Budgeted Capital Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
AEP Texas	$ —	$ 1.8	$ 629.4	$ 443.5	$ 94.7	$ 1,169.4
AEPTCo	—	—	1,374.1	—	56.3	1,430.4
APCo	37.3	43.4	339.7	267.7	74.0	762.1
I&M	33.4	153.8	83.6	248.7	105.4	624.9
OPCo	—	—	135.9	427.4	124.9	688.2
PSO	6.0	21.2	49.7	183.8	50.4	311.1
SWEPCo	40.1	39.5	126.5	122.6	46.8	375.5

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

2020 Budgeted Capital Expenditures by Registrant Subsidiary



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, 2019:

Payments Due by Period

Contractual Cash Obligations	Less Than	2-3 Years	4-5 Years	After	Total
			(in millions)		
Short-term Debt (a)	$ 2,838.3	$ —	$ —	$ —	$ 2,838.3
Interest on Fixed Rate Portion of Long-term Debt (b)	28.8	45.2	31.7	29.3	135.0
Fixed Rate Portion of Long-term Debt (c)	1,070.4	4,238.3	1,271.3	18,863.1	25,443.1
Variable Rate Portion of Long-term Debt (d)	528.3	799.0	175.1	—	1,502.4
Finance Lease Obligations (e)	72.7	121.3	107.0	64.4	365.4
Operating Lease Obligations (e)	269.9	499.2	136.8	169.7	1,075.6
Fuel Purchase Contracts (f)	1,047.0	1,105.0	234.4	111.4	2,497.8
Energy and Capacity Purchase Contracts	227.8	353.2	273.5	1,080.0	1,934.5
Construction Contracts for Capital Assets (g)	2,121.2	3,752.4	2,992.8	3,382.7	12,249.1
Total	$ 8,204.4	$ 10,913.6	$ 5,222.6	$ 23,700.6	$ 48,041.2

(a) Represents principal only, excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2019 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest.
(d) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 1.67% and 3.20% as of December 31, 2019.
(e) See Note 13 - Leases for additional information.
(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 pension funding requirements are not included in the above table. As of December 31, 2019, AEP expects to make contributions to the pension plans totaling $6 million in 2020. Estimated contributions of $119 million in 2021 and $123 million in 2022 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 95.8% funded as of December 31, 2019. See "Estimated Future Benefit Payments and Contributions" section of Note 8 for additional information.

In addition to the amounts disclosed in the contractual cash obligations table above, 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 for additional information.

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 December 2019, a tax extenders bill was signed into law to extend wind PTCs an additional year. Wind projects that begin construction in 2020 are now eligible for a 60% PTC or alternatively an 18% ITC in lieu of a PTC. See "Federal Tax Reform and Legislation" and "State Tax Legislation" sections of Note 12 for additional information.

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 its 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.

There can be no assurance, however, that these efforts will be effective to prevent interruption of services or other damages to AEP's business or operations in connection with any cyber-related incident.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

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 sheets. 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. See Note 5 - Effects of Regulation for additional information 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 $248 million and $255 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $(7) million, $(23) million and $37 million for the years ended December 31, 2019, 2018 and 2017, 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 $166 million and $178 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $(12) million, $(24) million and $11 million for the years ended December 31, 2019, 2018 and 2017, 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 $75 million and $59 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $16 million, $5 million and $5 million for the years ended December 31, 2019, 2018 and 2017, 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 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). 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)	**2019**	**2018**	**2017**
		(in millions)	
Pension Plans	$ 61.5	$ 82.9	$ 98.6
OPEB	(80.7)	(101.8)	(63.2)

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 2020, 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 5.75% for the Qualified Plan and 5.5% 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	
	2020 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2020 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	30%	7.70%	48%	7.27%
Fixed Income	54	4.18	50	3.85
Other Investments	15	7.96	—	—
Cash and Cash Equivalents	1	2.17	2	2.17
Total	100%		100%	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 5.75% for the Qualified Plan and 5.5% for the OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 15.81% for the year ended December 31, 2019 and an actual loss of 2.10% for the year ended December 31, 2018. The OPEB plans' assets had an actual gain of 20.93% for the year ended December 31, 2019 and an actual loss of 6.38% for the year ended December 31, 2018. 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, 2019, AEP had cumulative gains of approximately $209 million for the Qualified Plan that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial gains may result in increases in the future pension costs depending on several factors, including whether such gains 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, 2019 under this method was 3.25% for the Qualified Plan, 3.15% for the Nonqualified Plans and 3.3% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return on the Pension Plans' assets of 5.75%, discount rates of 3.25% and 3.15% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $107 million, $94 million and $81 million in 2020, 2021 and 2022, respectively. Based on an expected rate of return on the OPEB plans' assets of 5.5%, a discount rate of 3.3% and various other assumptions, management estimates OPEB plan credits will approximate $110 million, $111 million and $112 million in 2020, 2021 and 2022, 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 increased to $5.0 billion as of December 31, 2019 from $4.7 billion as of December 31, 2018 primarily due to higher investment returns. During 2019, the Qualified Plan paid $361 million and the Nonqualified Plans paid $6 million in benefits to plan participants. The value of AEP's OPEB plans' assets increased to $1.8 billion as of December 31, 2019 from $1.5 billion as of December 31, 2018 primarily due to higher investment returns. The OPEB plans paid $113 million in benefits to plan participants during 2019.

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, 2019 Benefit Obligations				
Discount Rate	$ (258.1)	$ 283.3	$ (64.4)	$ 71.0
Compensation Increase Rate	26.3	(24.3)	NA	NA
Cash Balance Crediting Rate	71.4	(66.1)	NA	NA
Health Care Cost Trend Rate	NA	NA	15.7	(15.3)
Effect on 2019 Periodic Cost				
Discount Rate	$ (12.7)	$ 13.9	$ (3.2)	$ 3.5
Compensation Increase Rate	5.3	(4.9)	NA	NA
Cash Balance Crediting Rate	13.5	(12.4)	NA	NA
Health Care Cost Trend Rate	NA	NA	2.0	(1.9)
Expected Return on Plan Assets	(23.7)	23.7	(7.5)	7.5

NA Not applicable.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards adopted in 2019 and standards 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. 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, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Senior Vice President of Treasury and Risk 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, 2018:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2019

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2018	$ 90.9	$ (101.0)	$ 164.5	$ 154.4
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(5.4)	(7.2)	(19.2)	(31.8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	8.3	8.3
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	9.8	9.8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(9.6)	4.6	—	(5.0)
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2019	$ 75.9	$ (103.6)	$ 163.4	135.7
Commodity Cash Flow Hedge Contracts				(125.5)
Interest Rate Cash Flow Hedge Contracts				4.6
Fair Value Hedge Contracts				14.5
Collateral Deposits				34.0
Total MTM Derivative Contract Net Assets as of December 31, 2019				$ 63.3

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.

(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.

(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets or accounts payable.

See Note 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 (includes non-derivative 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, 2019, credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2019, 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	$ 513.4	$ —	$ 513.4	2	$ 208.1
Split Rating	3.1	—	3.1	2	3.1
No External Ratings:					
Internal Investment Grade	135.8	—	135.8	4	82.2
Internal Noninvestment Grade	55.7	10.5	45.2	2	28.6
Total as of December 31, 2019	$ 708.0	$ 10.5	$ 697.5		

All exposure in the table above relates to either AEPSC or AEPEP. 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, 2019, 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, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.1	$ 1.2	$ 0.2	$ 0.1	$ 1.1	$ 1.8	$ 0.3	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 8.5	$ 1.1	$ 0.2	$ 4.0	$ 16.5	$ 2.7	$ 0.4

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 12 months ended December 31, 2019, 2018 and 2017, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $24 million, $25 million and $28 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, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1, 4, and 5 to the consolidated financial statements, the Company's consolidated 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. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future 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 matching income with its passage to customers in cost-based regulated rates. Management reviews the probability of recovery of regulatory assets and refund of regulatory liabilities at each balance sheet date, or whenever new events occur, whether influenced by regulatory commission orders, new legislation, or changes in the regulatory environment. As of December 31, 2019, there were $3.3 billion of deferred costs included in regulatory assets, $o.2 billion of which were pending final regulatory approval, and $8.5 billion of regulatory liabilities awaiting potential refund or future rate reduction, $0.5 billion of which were pending final regulatory determination.

The principal considerations for our determination that performing procedures relating to the accounting for the effects of cost-based regulation is a critical audit matter are there was significant judgment and estimation by management in the ongoing evaluation of the recovery of regulatory assets and refund of regulatory liabilities, and applying guidance contained in rate orders and other relevant evidence. This in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to management's judgments about the probability of recovery of regulatory assets and refund of regulatory liabilities, including estimates made to record recoveries, refunds and disallowances.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's assessment of regulatory proceedings, including the probability of recovery of regulatory assets and refund of regulatory liabilities, including management's development of the estimates made to record any recoveries, refunds and disallowances. These procedures also included, among others, evaluating the reasonableness of management's assessment of probability of future recovery for regulatory assets and refund of regulatory liabilities, and testing management's process and evaluating the reasonableness of management's estimates of amounts to be refunded or recovered and the time period over which the refunds will be made or the recoveries will occur. Testing of regulatory assets and liabilities, including those subject to pending rate cases, also involved evaluating the provisions and formulas outlined in rate orders, other regulatory correspondence, and application of regulatory precedents.

Valuation of Level 3 Risk Management Commodity Contracts

As described in Notes 1, 10 and 11 to the consolidated financial statements, the Company employs risk management commodity contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, over-the-counter swaps and options to accomplish its risk management strategies. Certain over-the-counter and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. The fair value of these risk management commodity contracts is estimated based on available market information using discounted cash flow models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. The main driver of the classification of risk management contracts within Level 3 in the fair value hierarchy is the lack of observable energy price curves in the market, which required management to apply significant judgment in developing its estimate of energy prices in future periods. Management utilized such unobservable pricing data to value its Level 3 risk management commodity contract assets and liabilities, which totaled $372.4 million and $262.5 million, as of December 31, 2019, respectively.

The principal considerations for our determination that performing procedures relating to the valuation of Level 3 risk management commodity contracts is a critical audit matter are there was significant judgment and estimation by management when developing the fair value of the commodity contracts. This in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to the unobservable assumptions used within management's discounted cash flow models, including projections of forward commodity prices, supply and demand levels, and future price volatility. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's valuation of the risk management commodity contracts, including controls over the assumptions used to value the Level 3 risk management commodity contracts. These procedures also included, among others, testing the data used in and management's process for developing the fair value of the Level 3 risk management commodity contracts. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and reasonableness of the assumptions used by management, including the forward commodity prices, supply and demand levels, and future price volatility.

Acquisition of Sempra Renewables LLC

As described in Notes 7 and 17 to the consolidated financial statements, the Company completed the acquisition of Sempra Renewables LLC for net consideration of $580.4 million in 2019. Management applied significant judgment in estimating the fair value of net assets acquired, which involved the use of significant estimates and assumptions, including the pricing and terms of the existing purchase power agreements, forecasted market power prices, expected wind farm net capacity, and discount rates reflecting risk inherent in the future cash flows and future power prices.

The principal considerations for our determination that performing procedures relating to the acquisition of Sempra Renewables LLC is a critical audit matter are there was significant audit effort and a high degree of auditor subjectivity in performing procedures relating to the fair value measurement of the net assets acquired due to the significant amount of judgment used by management when developing the estimates. Significant audit effort was required in evaluating the significant assumptions relating to the future cash flows, specifically, forecasted market power prices, expected wind farm net capacity, and discount rates. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the acquisition accounting, including controls over management's valuation of the acquired net assets and controls over development of the significant estimates and assumptions related to the future cash flows, specifically forecasted market power prices, expected wind farm net generation and discount rates. These procedures also included, among others, reading the purchase agreement and the related power purchase contracts, testing management's process for estimating the fair value of acquired net assets, and evaluating management's future cash flows and discount rates used to estimate the fair value of the acquired net assets, using professionals with specialized skill and knowledge to assist in doing so. Testing management's process included evaluating the appropriateness of the valuation methods and the reasonableness of the future cash flows, specifically market power prices, expected wind farm net capacity, and discount rates. Evaluating the reasonableness of forecasted market power prices involved evaluating the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third party market participant assumptions. Evaluating the reasonableness of expected wind farm net capacity involved evaluation against each wind farm's historical and expected generation. Discount rates were evaluated by considering the cost of capital of comparable businesses and other industry factors.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 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, 2019. 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, 2019.

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, 2019. 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, 2019, 2018 and 2017
(in millions, except per-share and share amounts)

	Years Ended December 31, 2019	2018	2017
REVENUES			
Vertically Integrated Utilities	$ 9,245.7	$ 9,556.7	$ 9,095.1
Transmission and Distribution Utilities	4,319.0	4,552.3	4,328.9
Generation & Marketing	1,721.8	1,818.1	1,771.4
Other Revenues	274.9	268.6	229.5
TOTAL REVENUES	15,561.4	16,195.7	15,424.9
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,940.9	2,359.4	2,346.5
Purchased Electricity for Resale	3,165.2	3,427.1	2,965.3
Other Operation	2,743.7	2,979.2	2,525.2
Maintenance	1,213.9	1,247.4	1,145.6
Asset Impairments and Other Related Charges	156.4	70.6	87.1
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Depreciation and Amortization	2,514.5	2,286.6	1,997.2
Taxes Other Than Income Taxes	1,234.5	1,142.7	1,059.4
TOTAL EXPENSES	12,969.1	13,513.0	11,899.9
OPERATING INCOME	2,592.3	2,682.7	3,525.0
Other Income (Expense):			
Other Income	26.6	18.2	34.6
Allowance for Equity Funds Used During Construction	168.4	132.5	93.7
Non-Service Cost Components of Net Periodic Benefit Cost	120.0	124.5	45.5
Gain on Sale of Equity Investment	—	—	12.4
Interest Expense	(1,072.5)	(984.4)	(895.0)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1,834.8	1,973.5	2,816.2
Income Tax Expense (Benefit)	(12.9)	115.3	969.7
Equity Earnings of Unconsolidated Subsidiaries	72.1	73.1	82.4
NET INCOME	1,919.8	1,931.3	1,928.9
Net Income (Loss) Attributable to Noncontrolling Interests	(1.3)	7.5	16.3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,921.1	$ 1,923.8	$ 1,912.6
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	493,694,345	492,774,600	491,814,651
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.89	$ 3.90	$ 3.89
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	495,306,238	493,758,277	492,611,067
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.88	$ 3.90	$ 3.88

See Notes to Financial Statements of Registrants beginning on page 68.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(21.1), $3.9 and $(1.4) in 2019, 2018 and 2017, Respectively	(79.4)	14.6	(2.6)
Securities Available for Sale, Net of Tax of $0, $0 and $1.9 in 2019, 2018 and 2017, Respectively	—	—	3.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(1.5), $(1.4) and $0.6 in 2019, 2018 and 2017, Respectively	(5.6)	(5.3)	1.1
Pension and OPEB Funded Status, Net of Tax of $15.3, $(8.8) and $46.7 in 2019, 2018 and 2017, Respectively	57.7	(33.0)	86.5
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(27.3)	(23.7)	88.5
TOTAL COMPREHENSIVE INCOME	1,892.5	1,907.6	2,017.4
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	(1.3)	7.5	16.3
TOTAL OTHER COMPREHENSIVE INCOME ATTIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,893.8	$ 1,900.1	$ 2,001.1

See Notes to Financial Statements of Registrants beginning on page 68.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(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, 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
Issuance of Common Stock	0.9	6.0	59.3				65.3
Common Stock Dividends				(1,345.5) (a)		(4.5)	(1,350.0)
Other Changes in Equity			(9.8) (b)			2.2	(7.6)
Acquisition of Sempra Renewables LLC						134.8	134.8
Acquisition of Santa Rita East						118.8	118.8
Net Income (Loss)				1,921.1		(1.3)	1,919.8
Other Comprehensive Loss					(27.3)		(27.3)
TOTAL EQUITY – DECEMBER 31, 2019	514.4	$ 3,343.4	$ 6,535.6	$ 9,900.9	$ (147.7)	$ 281.0	$ 19,913.2

(a) Cash dividends declared per AEP common share were $2.71, $2.53 and $2.39 for the years ended December 31, 2019, 2018 and 2017, respectively.
(b) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units. See “Equity Units” section of Note 14 for additional information.

See Notes to Financial Statements of Registrants beginning on page 68.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 246.8	$ 234.1
Restricted Cash (December 31, 2019 and 2018 Amounts Include $185.8 and $210, Respectively, Related to Transition Funding, Restoration Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	185.8	210.0
Other Temporary Investments (December 31, 2019 and 2018 Amounts Include $187.8 and $152.7, Respectively, Related to EIS and Transource Energy)	202.7	159.1
Accounts Receivable:		
Customers	625.3	699.0
Accrued Unbilled Revenues	222.4	209.3
Pledged Accounts Receivable – AEP Credit	873.9	999.8
Miscellaneous	27.2	55.2
Allowance for Uncollectible Accounts	(43.7)	(36.8)
Total Accounts Receivable	1,705.1	1,926.5
Fuel	528.5	319.0
Materials and Supplies	640.7	602.1
Risk Management Assets	172.8	162.8
Regulatory Asset for Under-Recovered Fuel Costs	92.9	150.1
Margin Deposits	60.4	141.4
Prepayments and Other Current Assets	242.1	208.8
TOTAL CURRENT ASSETS	4,077.8	4,113.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	22,762.4	21,699.9
Transmission	24,808.6	21,531.0
Distribution	22,443.4	21,195.4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,811.5	4,265.0
Construction Work in Progress	4,319.8	4,393.9
Total Property, Plant and Equipment	79,145.7	73,085.2
Accumulated Depreciation and Amortization	19,007.6	17,986.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	60,138.1	55,099.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,158.8	3,310.4
Securitized Assets	858.1	920.6
Spent Nuclear Fuel and Decommissioning Trusts	2,975.7	2,474.9
Goodwill	52.5	52.5
Long-term Risk Management Assets	266.6	254.0
Operating Lease Assets	957.4	—
Deferred Charges and Other Noncurrent Assets	3,407.3	2,577.4
TOTAL OTHER NONCURRENT ASSETS	11,676.4	9,589.8
TOTAL ASSETS	$ 75,892.3	$ 68,802.8

See Notes to Financial Statements of Registrants beginning on page 68.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018
(dollars in millions)

	December 31, 2019	December 31, 2018
CURRENT LIABILITIES		
Accounts Payable	$ 2,085.8	$ 1,874.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	710.0	750.0
Other Short-term Debt	2,128.3	1,160.0
Total Short-term Debt	2,838.3	1,910.0
Long-term Debt Due Within One Year (December 31, 2019 and 2018 Amounts Include $565.1 and $406.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)	1,598.7	1,698.5
Risk Management Liabilities	114.3	55.0
Customer Deposits	366.1	412.2
Accrued Taxes	1,357.8	1,218.0
Accrued Interest	243.6	231.7
Obligations Under Operating Leases	234.1	—
Regulatory Liability for Over-Recovered Fuel Costs	86.6	58.6
Other Current Liabilities	1,373.8	1,190.5
TOTAL CURRENT LIABILITIES	10,299.1	8,648.8
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2019 and 2018 Amounts Include $907 and $1,109.2, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)	25,126.8	21,648.2
Long-term Risk Management Liabilities	261.8	263.4
Deferred Income Taxes	7,588.2	7,086.5
Regulatory Liabilities and Deferred Investment Tax Credits	8,457.6	8,540.3
Asset Retirement Obligations	2,216.6	2,287.7
Employee Benefits and Pension Obligations	466.0	377.1
Obligations Under Operating Leases	734.6	—
Deferred Credits and Other Noncurrent Liabilities	719.8	782.6
TOTAL NONCURRENT LIABILITIES	45,571.4	40,985.8
TOTAL LIABILITIES	55,870.5	49,634.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	65.7	69.4
Contingently Redeemable Performance Share Awards	42.9	39.4
TOTAL MEZZANINE EQUITY	108.6	108.8
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2019	2018
Shares Authorized	600,000,000	600,000,000
Shares Issued	514,373,631	513,450,036

	2019	2018
(20,204,160 Shares were Held in Treasury as of December 31, 2019 and 2018, Respectively)	3,343.4	3,337.4
Paid-in Capital	6,535.6	6,486.1
Retained Earnings	9,900.9	9,325.3
Accumulated Other Comprehensive Income (Loss)	(147.7)	(120.4)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,632.2	19,028.4
Noncontrolling Interests	281.0	31.0
TOTAL EQUITY	19,913.2	19,059.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 75,892.3	$ 68,802.8

See Notes to Financial Statements of Registrants beginning on page 68.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	2,514.5	2,286.6	1,997.2
Rockport Plant, Unit 2 Operating Lease Amortization	136.5	—	—
Deferred Income Taxes	(17.8)	104.3	901.5
Asset Impairments and Other Related Charges	156.4	70.6	87.1
Allowance for Equity Funds Used During Construction	(168.4)	(132.5)	(93.7)
Mark-to-Market of Risk Management Contracts	(29.2)	(66.4)	(23.3)
Amortization of Nuclear Fuel	89.1	113.8	129.1
Pension and Postemployment Benefit Reserves	(24.6)	(42.8)	27.8
Pension Contributions to Qualified Plan Trust	—	—	(93.3)
Property Taxes	(73.8)	(59.1)	(29.5)
Deferred Fuel Over/Under-Recovery, Net	85.2	189.7	84.4
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Recovery of Ohio Capacity Costs, Net	34.1	67.7	83.2
Refund of Global Settlement	(16.5)	(5.5)	(98.2)
Change in Other Noncurrent Assets	(97.4)	119.8	(423.9)
Change in Other Noncurrent Liabilities	(116.1)	129.0	181.7
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	247.8	145.9	28.5
Fuel, Materials and Supplies	(248.2)	20.7	17.9
Accounts Payable	5.8	36.6	(58.0)
Accrued Taxes, Net	138.9	153.2	91.9
Rockport Plant, Unit 2 Operating Lease Payments	(147.7)	—	—
Other Current Assets	70.7	10.5	(60.7)
Other Current Liabilities	(189.0)	149.8	(181.8)
Net Cash Flows from Operating Activities	4,270.1	5,223.2	4,270.4
INVESTING ACTIVITIES			
Construction Expenditures	(6,051.4)	(6,310.9)	(5,691.3)
Purchases of Investment Securities	(1,576.0)	(2,067.8)	(2,314.7)
Sales of Investment Securities	1,494.2	2,010.0	2,256.3
Acquisitions of Nuclear Fuel	(92.3)	(46.1)	(108.0)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(918.4)	—	—
Proceeds from Sale of Merchant Generation Assets	—	—	2,159.6
Other Investing Activities	(0.6)	61.2	41.7
Net Cash Flows Used for Investing Activities	(7,144.5)	(6,353.6)	(3,656.4)
FINANCING ACTIVITIES			
Issuance of Common Stock	65.3	73.6	12.2
Issuance of Long-term Debt	4,536.6	4,945.7	3,854.1
Commercial Paper and Credit Facility Borrowings	—	205.6	—
Change in Short-term Debt, Net	928.3	271.4	(74.4)
Retirement of Long-term Debt	(1,220.8)	(2,782.0)	(3,087.9)
Commercial Paper and Credit Facility Repayments	—	(205.6)	—
Make Whole Premium on Extinguishment of Long-term Debt	(5.0)	(13.5)	(46.1)
Principal Payments for Finance Lease Obligations	(70.7)	(65.1)	(67.3)
Dividends Paid on Common Stock	(1,350.0)	(1,255.5)	(1,191.9)
Other Financing Activities	(20.8)	(12.7)	(3.6)
Net Cash Flows from (Used for) Financing Activities	2,862.9	1,161.9	(604.9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(11.5)	31.5	9.1
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	444.1	412.6	403.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 432.6	$ 444.1	$ 412.6

See Notes to Financial Statements of Registrants beginning on page 68.

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. 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 paid for certain legacy generation deferral balances that were fully recovered as of December 31, 2019 and continue to pay for certain legacy deferred generation-related costs through PUCO approved riders. 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. 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, Transition Funding (consolidated VIEs) and Restoration Funding (a consolidated VIE). 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). In July 2019, the Ohio Phase-in Recovery Funding securitization bonds matured. 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 Equity Method Investments and Note 18 - Property, Plant and Equipment for additional information.

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 and contractually restricted deposits held for the future payment of the remaining construction activities at the Santa Rita East wind generation facility.

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 sheets that sum to the total of the same amounts shown on the statement of cash flows:

	December 31, 2019			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 246.8	$ 3.1	$ 3.3	$ 3.7
Restricted Cash	185.8	154.7	23.5	—
Total Cash, Cash Equivalents and Restricted Cash	$ 432.6	$ 157.8	$ 26.8	$ 3.7

	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

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 Power Station, which is carried at the lower of average cost or net realizable value. Materials and supplies inventories are carried at average cost. AEP and SWEPCo reclassified approximately $23 million, as of December 31, 2018, from Fuel to Materials and Supplies related to Sabine.

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 "Securitized Accounts Receivable – 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, TXU Energy and Reliant Energy	**2019**	**2018**	**2017 (a)**
Percentage of Total Revenues	48%	45%	35%
Percentage of Accounts Receivable – Customers	43%	35%	31%

(a) TXU 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	**2019**	**2018**	**2017**
Percentage of Total Revenues	79%	77%	80%
Percentage of Total Accounts Receivable	78%	84%	85%

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.

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

In regulated jurisdictions, the Registrants record renewable energy credits (RECs) at cost. For AEP's competitive generation business, management records RECs at the lower of cost or market. The Registrants follow the inventory model for these RECs. RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. 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 RECs are reported in the Operating Activities section of the statements of cash flows. 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 RECs affects the determination of deferred fuel 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 derivatives 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.

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 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, purchased power is reflected in rates through various PUCO approved mechanisms. 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. Beginning in 2020, Arkansas for SWEPCo will start giving all margins from off-system sales to customers through the FAC. 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 of each calendar year 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.

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 on 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, the 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 for additional information.

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 and Production 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.

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 ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed into service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the cash tax benefit is recognized. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

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 a business, as defined by the accounting guidance for “Business Combinations,” management recognizes all acquired assets and liabilities at their fair value. To the extent that consideration exceeds the net fair value of the identified assets and liabilities, goodwill is recognized on the balance sheets. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at its 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 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	30%
Fixed Income	54%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	48%
Fixed Income	50%
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 or certain commingled funds). 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 generally 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 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.

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 investments.

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, 2019 and 2018, the fair value of securities on loan as part of the program was $246 million and $241 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2019 and 2018.

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 an external investment manager that 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. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF 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, 2019, AEP had performance shares and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, all outstanding performance shares and restricted stock units settle in AEP common stock. Performance units awarded prior to 2017 and restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vested to executive officers were settled in cash. During 2019, all of the remaining performance units and restricted stock units that settle in cash were settled. 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 shares 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 settled in shares of AEP common stock after the executive's service with AEP ends.

Performance shares 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, 2019, 2018 and 2017 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, 2019, 2018 and 2017, compensation cost is included in Net Income for the performance shares, 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 Entities (Applies to AEP and SWEPCo)

The equity method of accounting is used for equity investments where either AEP or SWEPCo 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 (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 various significant equity method investments, which include ETT, DHLC and five wind farms acquired in the purchase of Sempra Renewables LLC. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

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,					
	2019		2018		2017	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$1,921.1		$1,923.8		$1,912.6	
Weighted Average Number of Basic Shares Outstanding	493.7	$ 3.89	492.8	$ 3.90	491.8	$ 3.89
Weighted Average Dilutive Effect of Stock-Based Awards	1.6	(0.01)	1.0	—	0.8	(0.01)
Weighted Average Number of Diluted Shares Outstanding	495.3	$ 3.88	493.8	$ 3.90	492.6	$ 3.88

Equity Units issued in March 2019 are potentially dilutive securities but were excluded from the calculation of diluted EPS for the year ended December 31, 2019, as the dilutive stock price threshold was not met. See Note 14 - Financing Activities for additional information.

There were no antidilutive shares outstanding as of December 31, 2019, 2018 and 2017.

Reclassifications

Certain reclassifications have been made in the 2018 financial statements and notes to conform to the 2019 presentation.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2019, 2018 and 2017:

2019

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,203.7	$ 365.9	$ 176.0	$ 466.5	$ 330.6	$ 229.4	$ 162.5	$ 247.9
Amortization of Certain Securitized Assets	280.7	258.7	—	—	—	22.0	—	—
Amortization of Regulatory Assets and Liabilities	30.1	(2.3)	—	0.3	20.0	(10.5)	7.0	1.2
Total Depreciation and Amortization	$ 2,514.5	$ 622.3	$ 176.0	$ 466.8	$ 350.6	$ 240.9	$ 169.5	$ 249.1

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	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

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2019	2018	2017
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 1,022.5	$ 939.3	$ 858.3
Income Taxes	6.1	(24.7)	(1.1)
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	87.5	55.6	60.7
Construction Expenditures Included in Current Liabilities as of December 31,	1,341.1	1,120.4	1,330.8
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	—	71.8
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	0.1	4.0	—
Noncash Contribution of Assets by Noncontrolling Interest	—	84.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0.3	2.2	2.6
Noncontrolling Interest Assumed with Sempra Renewables LLC and Santa Rita East Acquisition	253.4	—	—
Liabilities Assumed with Sempra Renewable LLC and Santa Rita East Acquisition	32.4	—	—

2. NEW ACCOUNTING STANDARDS

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

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

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, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is 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 sheets. 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 sheets 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 sheets. See Note 13 - Leases for additional disclosures required by the new standard.

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

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of a cumulative-effect adjustment to the balance sheets. The adoption of the new standard did not have a material impact to financial position, and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

Implementation activities included: (1) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard and, (2) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management continues to develop disclosures to comply with the requirements of ASU 2016-13 that are required in the first quarter of 2020. Management will continue to monitor for any potential industry implementation issues.

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, 2019, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional details.

AEP

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2019	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ 136.3	$ (221.1)	$ (120.4)
Change in Fair Value Recognized in AOCI	(127.2)	(0.2) (a)	—	57.7	(69.7)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (b)	(0.2)	—	—	—	(0.2)
Purchased Electricity for Resale (b)	59.5	—	—	—	59.5
Interest Expense (b)	—	1.5	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—	12.1	—	12.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	59.3	1.5	(7.1)	—	53.7
Income Tax (Expense) Benefit	12.6	0.2	(1.5)	—	11.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	46.7	1.3	(5.6)	—	42.4
Net Current Period Other Comprehensive Income (Loss)	(80.5)	1.1	(5.6)	57.7	(27.3)
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)	$ 130.7	$ (163.4)	$ (147.7)

AEP

For the Year Ended December 31, 2018	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Securities Available for Sale	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	$ (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 (b)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (b)	(32.6)	—	—	—	—	(32.6)
Interest Expense (b)	—	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	(6.1)	(2.7)	—	—	(8.2)	(17.0)
ASU 2016-01 Adoption	—	—	(11.9)	—	—	(11.9)
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ —	$ 136.3	$ (221.1)	$ (120.4)

For the Year Ended December 31, 2017	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Securities Available for Sale	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	$ (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 (b)	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale (b)	28.8	—	—	—	—	28.8
Interest Expense (b)	—	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 Texas

For the Year Ended December 31, 2019	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, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
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	1.1	2.3
Balance in AOCI as of December 31, 2019	$ (3.4)	$ 4.9	$ (14.3)	$ (12.8)

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	$ (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 (b)	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	(0.9)	—	(1.8)	(2.7)
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)

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	$ (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 (b)	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)

APCo

For the Year Ended December 31, 2019	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, 2018	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)
Change in Fair Value Recognized in AOCI	—	—	13.4	13.4
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	2.1	—	2.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(3.2)	—	(4.3)
Income Tax (Expense) Benefit	(0.2)	(0.7)	—	(0.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.9)	(2.5)	—	(3.4)
Net Current Period Other Comprehensive Income (Loss)	(0.9)	(2.5)	13.4	10.0
Balance in AOCI as of December 31, 2019	$ 0.9	$ 9.2	$ (5.1)	$ 5.0

For the Year Ended December 31, 2018	Cash Flow Hedges Commodity	Cash Flow Hedges 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	$ —	$ 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 (b)	0.9	—	—	—	0.9
Interest Expense (b)	—	(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	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	$ —	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)

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	$ 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 (b)	(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

I&M

For the Year Ended December 31, 2019	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, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)
Change in Fair Value Recognized in AOCI	—	—	0.8	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.2)	—	1.8
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.2)	—	1.4
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.2)	0.8	2.2
Balance in AOCI as of December 31, 2019	$ (9.9)	$ 4.9	$ (6.6)	$ (11.6)

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 (b)	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	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

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 (b)	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)

OPCo

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 1.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(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)
Balance in AOCI as of December 31, 2019	$ —

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 (b)	(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	0.4
Balance in AOCI as of December 31, 2018	$ 1.0

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 (b)	(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

PSO

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 2.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(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)
Balance in AOCI as of December 31, 2019	$ 1.1

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 (b)	(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	0.5
Balance in AOCI as of December 31, 2018	$ 2.1

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 (b)	(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

SWEPCo

For the Year Ended December 31, 2019	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, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)
Change in Fair Value Recognized in AOCI	—	—	3.7	3.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(1.4)	—	0.5
Income Tax (Expense) Benefit	0.4	(0.3)	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.1)	—	0.4
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.1)	3.7	4.1
Balance in AOCI as of December 31, 2019	$ (1.8)	$ (1.3)	$ 1.8	$ (1.3)

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	$ (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 (b)	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	(1.3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)

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	$ (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 (b)	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)

(a) The change in fair value includes $4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the year ended December 31, 2019. See “Sempra Renewables LLC” section of Note 17 for additional information.

(b) Amounts reclassified to the referenced line item on the statements of income.

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)

2019 Texas Base Rate Case

In May 2019, AEP Texas filed a request with the PUCT for a $56 million annual increase in rates based upon a proposed 10.5% return on common equity. The filing includes a proposed Income Tax Refund Rider that will refund $21 million annually of Excess ADIT that is primarily not subject to normalization requirements. The rate case also seeks a prudence determination on all transmission and distribution capital additions through 2018 included in interim rates from 2008 to December 2019. As of December 31, 2019, AEP Texas' cumulative revenues from transmission and distribution interim rate increases are estimated to be approximately $1.4 billion and are subject to reconciliation in this base rate case.

In November 2019, ALJs issued a Proposal for Decision recommending a $60 million annual rate reduction based upon a 9.4% return on common equity. The ALJs also recommended disallowances that could potentially result in write-offs of $84 million related to capital incentives and $5 million related to other plant additions. Additionally, the ALJs recommended that AEP Texas should be required to file an application for a separate proceeding to determine if any refunds are required associated with any disallowances on distribution or transmission capital investments.

In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity. The agreement provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The agreement includes disallowances of $23 million related to capital investments recorded through 2018 and $4 million related to rate case expenses. In addition, AEP Texas will refund: (a) $77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) $31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) $30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. Per the agreement, AEP Texas is required to file its next base rate case within four years of the date of the final order. The agreement also: (a) states future financially based capital incentives will not be included in interim transmission and distribution rates, (b) contains various ring-fencing provisions and (c) will allow the PUCT to decide whether to adopt a dividend restriction ring-fencing provision.

As a result of the stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million in December 2019 related to capital investments, which included $10 million of current year investments, in Asset Impairments and Other Related Charges on the statements of income, (b) recorded a $30 million provision for refund on the statements of income for revenues previously collected through rates and (c) wrote-off $4 million of rate case expenses to Other Operation on the statements of income. The PUCT is expected to issue an order in the first quarter of 2020. Upon approval of the 2019 Texas Base Rate Case, AEP Texas will refund $275 million of Excess ADIT associated with certain depreciable property using ARAM to transmission customers. AEP Texas will determine how to refund the remaining Excess ADIT that is not subject to normalization requirements in future proceedings. If the final order from the PUCT requires refunds or authorizes disallowances in excess of the amounts included within the February 2020 stipulation and settlement agreement, it could reduce future net income and cash flows and impact financial condition.

Texas Storm Cost Securitization

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. In March 2019, AEP Texas filed a request to securitize total estimated distribution-related system restoration costs with the PUCT, which included estimated carrying costs. In June 2019, the PUCT approved the financing order. As part of the financing order, AEP Texas agreed to offset $64 million of Excess ADIT that is not subject to normalization requirements against the total distribution-related system restoration costs. In September 2019, AEP Texas issued $235 million of securitization bonds. The securitization bonds included carrying costs of $33 million, which includes $21 million of debt carrying costs recorded as a reduction to Interest Expense in 2019.

The stipulation and settlement agreement discussed in the 2019 Texas Base Rate Case above does not require any adjustments to the remaining $95 million of estimated net transmission-related system restoration costs and these costs will be recovered in base rates if the agreement is approved by the PUCT. 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

Under a 2015 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. The 2015 amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

Further amendments to Virginia law impacting investor-owned utilities were enacted, effective July 1, 2018, that require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 earnings test years (triennial review). Triennial reviews are subject to an earnings test which provides that 70% of any earnings in excess of 70 basis points above APCo's Virginia SCC authorized ROE would be refunded to customers. In such case, the Virginia SCC could also lower APCo's Virginia retail base rates on a prospective basis. In November 2018, the Virginia SCC authorized a ROE of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period.

Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. In 2015, APCo retired the Sporn Plant, the Kanawha River Plant, the Glen Lyn Plant, Clinch River Unit 3 and the coal portions of Clinch River Units 1 and 2 (collectively, the retired coal-fired generation assets). The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets in December 2019. This expense is included in Asset Impairments and Other Related Charges on the statements of income. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

Inclusive of the $93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo estimates its Virginia earnings for the triennial period to be below the authorized ROE range. If any APCo Virginia jurisdictional costs are not recoverable or refunds of revenues collected from customers during the triennial review period, it could 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 Triennial Review of APCo's earnings, 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 March 2019, the Virginia SCC issued an order to reduce APCo's base rates to refund: (a) $40 million annually for ongoing annual tax savings, (b) $9 million annually of Excess ADIT associated with certain depreciable property using ARAM, (c) $94 million of Excess ADIT that is not subject to normalization requirements over three years and (d) a one-time credit of $22 million for estimated excess taxes collected from customers as a result of Tax Reform during the 15-month period ending March 31, 2019.

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.

In February 2019, the WVPSC issued an order approving a stipulation and settlement agreement between APCo, WPCo, WVPSC staff and certain intervenors. The agreement included an 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 also included: (a) $18 million ($14 million related to APCo) of increased annual depreciation expense, (b) a $24 million refund ($19 million related to APCo) over two years, through a rider beginning March 2019, of Excess ADIT that is not subject to normalization requirements, (c) the utilization of $14 million ($12 million related to APCo) of Excess ADIT that is not subject to normalization requirements to offset regulatory asset balances relating to ENEC, (d) an agreement to seek WVPSC approval of economic incentive programs to provide funds to aid in industrial and commercial development and (e) an agreement, barring any unforeseen events, to not initiate another base rate proceeding prior to April 1, 2020.

<u>ETT Rate Matters</u> (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 semi-annual interim rate changes which are subject to review and possible true-up in the next base rate proceeding. Through December 31, 2019, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $1 billion. 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 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for base rate proceedings. The rule requires ETT to file for a comprehensive base rate review no later than February 1, 2021.

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

Michigan Tax Reform

In October 2018, I&M made a filing with the MPSC recommending to: (a) refund Excess ADIT associated with certain depreciable property using ARAM and (b) refund Excess ADIT that is not subject to normalization requirements over ten years. In November 2019, the MPSC issued an order authorizing I&M to: (a) refund $48 million of Excess ADIT associated with certain depreciable property using ARAM and (b) refund $28 million of Excess ADIT that is not subject to normalization requirements over ten years. In January 2020, the MPSC issued an order in the 2019 Michigan Base Rate Case that changed the refund period from ten years to five years. See "2019 Michigan Base Rate Case" below.

2019 Indiana Base Rate Case

In May 2019, I&M filed a request with the IURC for a $172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes $78 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes $52 million related to proposed investments and $26 million related to increased depreciation rates. The request includes the continuation of all existing riders and a new Automated Metering Infrastructure (AMI) rider for proposed meter projects.

In August 2019, various intervenors filed testimony that recommended annual rate increases ranging from $2 million to $33 million based upon a return on common equity ranging from 9% to 9.73%. The difference between I&M's requested annual base rate increase and the intervenor's recommendations are primarily due to: (a) proposed denial of return on and of certain new plant investments, (b) proposed lower depreciation rates, (c) a reduction in the requested return on common equity and (d) exclusion of I&M's proposed re-allocation of capacity costs related to I&M's June 2020 loss of a significant FERC wholesale contract. In addition, certain intervenors recommended disallowances that could potentially result in write-offs of $41 million related to the remaining book value of existing Indiana jurisdictional meters if I&M is approved to deploy AMI meters as initially requested and $11 million associated with certain Cook Plant study costs.

In September 2019, I&M filed testimony rebutting the various intervenors' recommendations. In October 2019, a hearing at the IURC was held. The IURC is expected to issue an order on this case in the first quarter of 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2019 Michigan Base Rate Case

In June 2019, I&M filed a request with the MPSC for a $58 million annual increase. The requested increase in Michigan rates would be phased in through June 2020 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes $19 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes $13 million related to proposed investments and $6 million related to increased depreciation rates. The proposed annual increase also includes $10 million for annual lost revenue related to the Michigan Electric Customer Choice Program that began in 2019.

In January 2020, the MPSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of $36 million based upon a 9.86% return on common equity effective with the first billing cycle of February 2020. The order also requires I&M to amortize and refund to customers through I&M Michigan base rates: (a) Excess ADIT that is not subject to normalization (over a period of five years starting February 2020) and (b) Excess ADIT associated with certain depreciable property using ARAM. Additionally, the order states that I&M will not be allowed to file its next base rate case before 2022.

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio ESP Filings

In 2016, OPCo filed a proposal to extend the ESP through May 2024. In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders. In January 2020, the Ohio Supreme Court affirmed the PUCO order, rejecting the filed appeal.

OPCo's Enhanced Service Reliability Rider (ESRR) authorized under the ESP is subject to annual audits. In May 2018, the PUCO staff filed comments indicating that 2016 spending under the ESRR was subject to authorized limits and that OPCo overspent those limits. In March 2019, the PUCO staff filed additional comments that OPCo overspent the authorized limit in 2017. Management believes that both 2016 and 2017 ESRR spending is not subject to an authorized limit and that a spending limit was not established until 2018, as part of the ESP extension. A hearing was held in May 2019 to address the 2016 audit. In December 2019, the PUCO issued an order finding that OPCo's 2016 ESRR spending was not subject to an authorized limit. If it is determined OPCo did have an authorized spending limit under the ESRR in 2017, and refunds are ordered, it would 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 Retail Stability Rider costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In February 2019, the PUCO issued an order that OPCo did not have significantly excessive earnings in 2016. As a result of the order, OPCo reversed the $58 million provision in the first quarter of 2019.

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

2018 Oklahoma Base Rate Case

In 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 included $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates included 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 March 2019, the OCC issued an order approving a stipulation and settlement agreement for a $46 million annual increase, based on a 9.4% return on equity effective with the first billing cycle of April 2019. The order also included agreements between the parties that: (a) depreciation rates will remain unchanged, (b) PSO will file a new base rate request no earlier than October 2020 and no later than October 2021 and (c) PSO will refund Excess ADIT that is not subject to normalization requirements over five years instead of the ten years ordered in the Oklahoma Tax Reform case. The order did not approve the performance-based rate plan but instead provided for an expansion of the SPP Transmission Tariff that tracks previously untracked SPP costs and a new Distribution Reliability and Safety Rider that provides additional revenues capped at $5 million per year for distribution projects related to safety and reliability that are not normal distribution replacements.

<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 January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In May 2019, various intervenors filed replies to the petition. In July 2019, SWEPCo filed its response to these replies. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court.

As of December 31, 2019, 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. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and 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. In June 2019, the LPSC staff issued its report which reaffirmed its $11 million refund recommendation. The report also contends that SWEPCo's requested annual rate increase of $18 million, which was implemented in August 2018, is overstated by $4 million and proposes an annual rate increase of $14 million. Additionally, the report recommends SWEPCo refund the excess over-collections associated with the $4 million difference for the period of August 2018 through the implementation of new rates. In July 2019, the LPSC approved the $11 million refund. A decision by the LPSC on the remaining formula rate plan issues is expected in the first half of 2020.

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 environmental regulations for Welsh Plant, Units 1 and 3 could total approximately $520 million, excluding AFUDC. As of December 31, 2019, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. SWEPCo has received approval to recover $340 million of its in-service investments related to environmental controls installed at Welsh Plant through base rates in its Arkansas, Louisiana and Texas jurisdictions. SWEPCo also recovers a portion of its investments related to environmental controls installed at Welsh Plant through wholesale formula rates. See "2016 Texas Base Rate Case," "2018 Louisiana Formula Rate Filing" and "2019 Arkansas Base Rate Case" disclosures for additional information. SWEPCo will seek recovery of future costs that have not yet been approved through base rate cases. If any of the remaining costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2019 Arkansas Base Rate Case

In February 2019, SWEPCo filed a request with the APSC for a $75 million increase in Arkansas base rates based upon a proposed 10.5% return on common equity. The filing requested rate base treatment for the Stall Plant and environmental retrofits that were being recovered through riders. Eliminating these riders would result in a net annual requested base rate increase of $58 million. The proposed net annual increase included $12 million related to vegetation management to improve the reliability of its Arkansas distribution system. The filing also provided notice of SWEPCo's proposal to have its rates regulated under the formula rate review mechanism authorized by Arkansas law, including a Formula Rate Review Rider. In October 2019, SWEPCo reduced its requested base rate increase from $75 million to $67 million.

In December 2019, the APSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of $53 million ($24 million net of amounts currently recovered through riders) based upon a 9.45% return on common equity. The order modified the stipulation and settlement agreement and included a disallowance of $4 million for previously recorded capital incentives. The base rate increase includes $6 million for increased annual depreciation expense and became effective with the first billing cycle in January 2020. The order provides recovery for: (a) the Stall Plant, (b) environmental retrofit projects and (c) the remaining net book value, with a debt return for investors, of Welsh Unit 2. The order also states that SWEPCo's rates will be regulated under the formula rate mechanism authorized by Arkansas law, which includes a Formula Rate Review Rider. Additionally, SWEPCo agreed to make the necessary filings with the APSC, at least 12 months in advance, to seek regulatory approval to retire the Dolet Hills Power Station no later than December 31, 2026.

FERC Rate Matters

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 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). The settlement agreement: (a) established 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) required 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) increased 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 normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

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. 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. In June 2019, the FERC approved an unopposed settlement agreement between AEP's transmission owning subsidiaries within SPP and the complainants. The settlement agreement established a base ROE of 10% (10.50% inclusive of the RTO incentive adder of 0.5%) effective January 1, 2019. Additionally, refunds including carrying charges were made from the date of the first complaint through December 31, 2018. Refunds for the period prior to 2019 were made at the time of the 2019 true-up of 2018 rates. Refunds from January 2019 onward will conclude with the 2020 true-up of 2019 rates.

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 resolving all outstanding issues. In June 2019, the FERC approved the settlement agreement.

5. EFFECTS OF REGULATION

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

Regulated Generating Units to be Retired (Applies to AEP, PSO and SWEPCo)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. See "2018 Oklahoma Base Rate Case" for additional information.

In January 2020, management announced that the Dolet Hills Power Station is probable of abandonment and is to be retired by December 2026. See "Dolet Hills Lignite Company Operations" section of Executive Overview, "2019 Arkansas Base Rate Case" section of Note 4, and "DHLC" section of Note 17 for additional information.

The table below summarizes the plant investments and their cost of removal, currently being recovered, as well as regulatory assets for accelerated depreciation for the generating units as of December 31, 2019.

Plant	Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset		Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
				(dollars in millions)					
Oklaunion Power Station	$ 106.7	$ 86.6	$ 20.1	$ 27.4	(a)	$ 3.2	$ 5.1	2020	27 years
Dolet Hills Power Station	338.9	194.2	144.7	—	(b)	5.8	23.6	2026	27 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.

(b) Beginning in January 2020, SWEPCo began recording a regulatory asset for accelerated depreciation.

Dolet Hills Power Station and Related Fuel Operations (Applies to AEP and SWEPCo)

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo's settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. Management also continues to monitor the economic viability of the Dolet Hills Power Station and DHLC mining operations, which may result in a decision to seek permission from appropriate regulatory agencies to discontinue operations earlier than 2026.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $157 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of December 31, 2019, DHLC has unbilled fixed costs of $106 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of December 31, 2019, Oxbow has unbilled fixed costs of $22 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

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

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining Recovery Period
	2019	2018	
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 44.7	$ 101.7	1 year
Under-recovered Fuel Costs - does not earn a return	48.2	48.4	1 year
Total Current Regulatory Assets	$ 92.9	$ 150.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 35.2	$ 50.3	
Kentucky Deferred Purchased Power Expenses	30.2	14.5	
Oklaunion Power Station Accelerated Depreciation	27.4	5.5	
Other Regulatory Assets Pending Final Regulatory Approval	0.7	9.3	
Total Regulatory Assets Currently Earning a Return	93.5	79.6	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	30.1	35.3	
Vegetation Management Program - AEP Texas (a)	29.4	—	
Cook Plant Study Costs	7.6	—	
Storm-Related Costs (b)	7.2	152.4	
Asset Retirement Obligation - Louisiana	7.2	5.3	
Other Regulatory Assets Pending Final Regulatory Approval	6.7	15.4	
Total Regulatory Assets Currently Not Earning a Return	88.2	208.4	
Total Regulatory Assets Pending Final Regulatory Approval (c)	181.7	288.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	690.5	680.9	23 years
Plant Retirement Costs - Asset Retirement Obligation Costs	87.4	64.3	21 years
Meter Replacement Costs	65.4	74.4	8 years
Environmental Control Projects	41.0	43.4	21 years
Cook Plant Uprate Project	32.6	35.0	14 years
Ohio Distribution Decoupling	31.4	12.3	2 years
Advanced Metering System	26.5	45.3	2 years
Storm-Related Costs	21.3	31.1	3 years
Mitchell Plant Transfer - West Virginia	16.2	17.0	21 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15.1	16.1	15 years
Cook Plant Turbine	13.4	15.8	19 years
Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	48.4	46.1	various
Total Regulatory Assets Currently Earning a Return	1,089.2	1,139.5	

Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,309.8	1,326.6	11 years
Unamortized Loss on Reacquired Debt	129.0	134.2	29 years
Unrealized Loss on Forward Commitments	106.8	104.6	13 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Vegetation Management - West Virginia	43.6	26.6	2 years
Postemployment Benefits	34.2	35.6	4 years
Plant Retirement Costs - Asset Retirement Obligation Costs	28.8	21.6	23 years
Medicare Subsidy	23.2	27.9	5 years
Peak Demand Reduction/Energy Efficiency	18.6	31.9	7 years
PJM/SPP Annual Formula Rate True Up	7.3	22.0	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	122.8	94.3	various
Total Regulatory Assets Currently Not Earning a Return	1,887.9	1,882.9	
Total Regulatory Assets Approved for Recovery	2,977.1	3,022.4	
Total Noncurrent Regulatory Assets	$ 3,158.8	$ 3,310.4	

(a) Includes $26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.

(b) In September 2019, AEP Texas securitized $235 million of storm-related costs. As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See “Texas Storm Cost Securitization” section of Note 4 - Rate Matters for additional information.

(c) In 2015, APCo recorded a $91 million reduction, before cost of removal which was $11 million and $20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo’s Virginia jurisdiction. The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management’s interpretation of Virginia law and more certainty regarding APCo’s triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

	AEP		
	December 31,		Remaining
Current Regulatory Liabilities	2019	2018	Refund Period
	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 77.5	$ 35.7	1 year
Over-recovered Fuel Costs - does not pay a return	9.1	22.9	1 year
Total Current Regulatory Liabilities	$ 86.6	$ 58.6	
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	571.8	1,025.3	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	291.0	695.0	(c) (g)
Total Income Tax Related Regulatory Liabilities	862.8	1,720.3	
Total Regulatory Liabilities Pending Final Regulatory Determination	863.0	1,720.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,876.7	2,742.8	(d)
Ohio Basic Transmission Cost Rider	37.2	68.8	2 years
Excess Earnings	8.3	8.9	34 years
Deferred Investment Tax Credits	6.2	8.7	41 years
Other Regulatory Liabilities Approved for Payment	6.1	8.9	various
Total Regulatory Liabilities Currently Paying a Return	2,934.5	2,838.1	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,236.0	828.5	(e)
Deferred Investment Tax Credits	215.3	204.9	43 years
PJM Transmission Enhancement Refund	67.3	164.2	6 years
Transition and Restoration Charges - Texas	50.5	46.0	10 years
Spent Nuclear Fuel	43.6	42.9	(e)
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years
Virginia Transmission Rate Adjustment Clause	28.1	11.3	2 years
Deferred Gain on Sale of Rockport Unit 2	27.2	—	3 years
Peak Demand Reduction/Energy Efficiency	23.0	17.5	2 years
Unrealized Gain on Forward Commitments	17.7	45.9	5 years
Other Regulatory Liabilities Approved for Payment	70.0	73.5	various
Total Regulatory Liabilities Currently Not Paying a Return	1,808.4	1,477.8	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	3,303.0	2,925.7	(f)
Excess ADIT that is Not Subject to Rate Normalization Requirements	890.5	864.3	17 years
Income Taxes Subject to Flow Through	(1,341.8)	(1,286.1)	56 years
Total Income Tax Related Regulatory Liabilities	2,851.7	2,503.9	
Total Regulatory Liabilities Approved for Payment	7,594.6	6,819.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,457.6	$ 8,540.3	

(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) Includes $275 million that will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.

(c) Includes $71 million from a stipulation and settlement agreement filed in February 2020. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.

(d) Relieved as removal costs are incurred.

(e) Relieved when plant is decommissioned.

(f) Refunded using ARAM.

(g) 2019 and 2018 amounts include approximately $172 million related to AEP Transmission Holdco's investment in ETT and Transource Energy. AEP Transmission Holdco expects to amortize the balance commensurate with the return of Excess ADIT to ETT and Transource Energy's customers.

Regulatory Assets:	AEP Texas December 31, 2019	2018	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Vegetation Management Program (a)	$ 29.4	$ —	
Storm-Related Costs (b)	—	152.4	
Other Regulatory Assets Pending Final Regulatory Approval	1.4	0.2	
Total Regulatory Assets Pending Final Regulatory Approval	30.8	152.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	35.2	40.1	8 years
Advanced Metering System	26.5	45.3	2 years
Total Regulatory Assets Currently Earning a Return	61.7	85.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	172.0	176.9	11 years
Unamortized Loss on Reacquired Debt	6.4	6.0	18 years
Other Regulatory Assets Approved for Recovery	9.7	9.1	various
Total Regulatory Assets Currently Not Earning a Return	188.1	192.0	
Total Regulatory Assets Approved for Recovery	249.8	277.4	
Total Noncurrent Regulatory Assets	$ 280.6	$ 430.0	

(a) Includes $26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.

(b) In September 2019, AEP Texas securitized $235 million of storm-related costs. As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See “Texas Storm Cost Securitization” section of Note 4 - Rate Matters for additional information.

Regulatory Liabilities:	AEP Texas December 31, 2019	AEP Texas December 31, 2018	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	$ 274.9	$ 277.1	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	87.1	141.4	(c)
Total Regulatory Liabilities Pending Final Regulatory Determination	362.0	418.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	689.6	645.2	(d)
Excess Earnings	5.8	6.3	12 years
Advanced Metering Infrastructure Surcharge	4.3	8.5	1 year
Total Regulatory Liabilities Currently Paying a Return	699.7	660.0	
Regulatory Liabilities Currently Not Paying a Return			
Transition and Restoration Charges	50.5	46.0	10 years
Deferred Investment Tax Credits	9.6	10.8	43 years
Other Regulatory Liabilities Approved for Payment	4.8	—	various
Total Regulatory Liabilities Currently Not Paying a Return	64.9	56.8	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	236.5	251.8	(e)
Income Taxes Subject to Flow Through	(46.2)	(42.8)	13 years
Total Income Tax Related Regulatory Liabilities	190.3	209.0	
Total Regulatory Liabilities Approved for Payment	954.9	925.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,316.9	$ 1,344.3	

(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) Will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.
(c) Includes $71 million from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.
(d) Relieved as removal costs are incurred.
(e) Refunded using ARAM.

	AEPTCo		
	December 31,		Remaining Recovery Period
Regulatory Assets:	2019	2018	
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Not Earning a Return			
PJM/SPP Annual Formula Rate True Up	$ 4.2	$ 12.9	2 years
Total Regulatory Assets Approved for Recovery	4.2	12.9	
Total Noncurrent Regulatory Assets	$ 4.2	$ 12.9	

	AEPTCo		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	2019	2018	
	(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	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	4.5	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	78.4	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	141.0	99.5	(b)
Total Regulatory Liabilities Currently Paying a Return	141.0	99.5	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	535.7	453.4	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	(35.4)	(28.5)	9 years
Income Taxes Subject to Flow Through	(100.4)	(81.5)	44 years
Total Income Tax Related Regulatory Liabilities	399.9	343.4	
Total Regulatory Liabilities Approved for Payment	540.9	442.9	
Total Noncurrent Regulatory Liabilities	$ 540.9	$ 521.3	

(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) Refunded using ARAM.

Regulatory Assets:	APCo December 31, 2019	APCo December 31, 2018	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Virginia - earns a return	$ 36.8	$ 82.4	1 year
Under-recovered Fuel Costs, West Virginia - does not earn a return	5.7	17.2	1 year
Total Current Regulatory Assets	$ 42.5	$ 99.6	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ 0.5	$ 9.0	
Total Regulatory Assets Currently Earning a Return	0.5	9.0	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	30.1	35.3	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.6	
Total Regulatory Assets Currently Not Earning a Return	30.1	35.9	
Total Regulatory Assets Pending Final Regulatory Approval (a)	30.6	44.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant - West Virginia	86.4	85.3	24 years
Other Regulatory Assets Approved for Recovery	0.5	1.2	various
Total Regulatory Assets Currently Earning a Return	86.9	86.5	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	160.8	172.2	11 years
Unamortized Loss on Reacquired Debt	85.5	89.3	23 years
Vegetation Management Program - West Virginia	43.6	26.6	2 years
Peak Demand Reduction/Energy Efficiency	19.5	19.7	7 years
Postemployment Benefits	15.9	18.0	4 years
Virginia Generation Rate Adjustment Clause	5.1	10.3	2 years
Other Regulatory Assets Approved for Recovery	9.3	8.3	various
Total Regulatory Assets Currently Not Earning a Return	339.7	344.4	
Total Regulatory Assets Approved for Recovery	426.6	430.9	
Total Noncurrent Regulatory Assets	$ 457.2	$ 475.8	

(a) In 2015, APCo recorded a $91 million reduction, before cost of removal which was $11 million and $20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo's Virginia jurisdiction. The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

Regulatory Liabilities:	APCo December 31, 2019	APCo December 31, 2018	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	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	283.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	551.9	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	635.3	618.3	(b)
Deferred Investment Tax Credits	0.5	1.0	41 years
Total Regulatory Liabilities Currently Paying a Return	635.8	619.3	
Regulatory Liabilities Currently Not Paying a Return			
Virginia Transmission Rate Adjustment Clause	28.1	11.3	2 years
PJM Transmission Enhancement Refund	19.5	47.7	6 years
Unrealized Gain on Forward Commitments	9.3	34.7	5 years
Consumer Rate Relief - West Virginia	5.4	8.8	1 year
Other Regulatory Liabilities Approved for Payment	3.3	3.9	various
Total Regulatory Liabilities Currently Not Paying a Return	65.6	106.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	718.9	453.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	210.7	84.5	9 years
Income Taxes Subject to Flow Through	(362.3)	(365.9)	23 years
Total Income Tax Related Regulatory Liabilities	567.3	172.1	
Total Regulatory Liabilities Approved for Payment	1,268.7	897.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,268.7	$ 1,449.7	

(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) Refunded using ARAM.

	I&M		
	December 31,		Remaining Recovery Period
Regulatory Assets:	**2019**	**2018**	
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 3.0	$ —	1 Year
Total Current Regulatory Assets	$ 3.0	$ —	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Cook Plant Study Costs	$ 7.6	$ —	
Other Regulatory Assets Pending Final Regulatory Approval	0.1	3.3	
Total Regulatory Assets Pending Final Regulatory Approval	7.7	3.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	214.9	232.2	9 years
Cook Plant Uprate Project	32.6	35.0	14 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15.1	16.1	15 years
Cook Plant Turbine	13.4	15.8	19 years
Rockport Plant Dry Sorbent Injection System - Indiana	10.2	11.5	8 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	5.4	5.7	19 years
Other Regulatory Assets Approved for Recovery	4.8	2.4	various
Total Regulatory Assets Currently Earning a Return	296.4	318.7	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	67.5	84.9	11 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Unamortized Loss on Reacquired Debt	17.2	18.7	29 years
Postemployment Benefits	7.2	6.5	4 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	22.3	22.8	various
Total Regulatory Assets Currently Not Earning a Return	178.0	190.5	
Total Regulatory Assets Approved for Recovery	474.4	509.2	
Total Noncurrent Regulatory Assets	$ 482.1	$ 512.5	

Regulatory Liabilities:	I&M December 31, 2019	I&M December 31, 2018	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Michigan - pays a return	$ —	$ 4.5	
Over-recovered Fuel Costs, Indiana - does not pay a return	6.1	22.9	1 year
Total Current Regulatory Liabilities	$ 6.1	$ 27.4	
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	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	40.6	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	165.6	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	166.7	182.5	(b)
Other Regulatory Liabilities Approved for Payment	0.3	—	various
Total Regulatory Liabilities Currently Paying a Return	167.0	182.5	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,236.0	828.5	(c)
Spent Nuclear Fuel	43.6	42.9	(c)
Deferred Investment Tax Credits	25.8	29.4	20 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	17.0	—	2 years
PJM Transmission Enhancement Refund	11.8	29.1	6 years
Deferred Gain on Sale of Rockport Unit 2	10.9	—	3 years
Other Regulatory Liabilities Approved for Payment	24.9	24.0	various
Total Regulatory Liabilities Currently Not Paying a Return	1,370.0	953.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	470.9	362.0	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	184.5	192.6	5 years
Income Taxes Subject to Flow Through	(301.0)	(282.1)	19 years
Total Income Tax Related Regulatory Liabilities	354.4	272.5	
Total Regulatory Liabilities Approved for Payment	1,891.4	1,408.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,891.4	$ 1,574.5	

(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) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

Regulatory Assets:	OPCo December 31, 2019	2018	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ —	$ 0.4	
Total Current Regulatory Assets	$ —	$ 0.4	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 1.0	
Total Regulatory Assets Pending Final Regulatory Approval	0.1	1.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Distribution Decoupling	31.4	12.3	2 years
Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	—	0.9	
Total Regulatory Assets Currently Earning a Return	31.4	71.0	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	167.3	181.5	11 years
Unrealized Loss on Forward Commitments	103.6	100.2	13 years
Smart Grid Costs	13.7	8.1	2 years
Distribution Investment Rider	10.9	—	2 years
Postemployment Benefits	7.6	7.9	4 years
Unamortized Loss on Reacquired Debt	5.3	6.5	19 years
Other Regulatory Assets Approved for Recovery	11.9	11.3	various
Total Regulatory Assets Currently Not Earning a Return	320.3	315.5	
Total Regulatory Assets Approved for Recovery	351.7	386.5	
Total Noncurrent Regulatory Assets	$ 351.8	$ 387.5	

Regulatory Liabilities:	OPCo December 31, 2019	2018	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ 2.8	$ —	1 year
Total Current Regulatory Liabilities	$ 2.8	$ —	
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 Pending Final Regulatory Determination	0.2	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	446.3	436.6	(b)
Ohio Basic Transmission Cost Rider	37.2	68.8	2 years
Other Regulatory Liabilities Approved for Payment	1.3	0.4	various
Total Regulatory Liabilities Currently Paying a Return	484.8	505.8	
Regulatory Liabilities Currently Not Paying a Return			
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years
PJM Transmission Enhancement Refund	29.4	71.3	6 years
Peak Demand Reduction/Energy Efficiency	19.7	14.9	2 years
Distribution Investment Rider	—	7.8	
Other Regulatory Liabilities Approved for Payment	2.9	11.3	various
Total Regulatory Liabilities Currently Not Paying a Return	81.7	148.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	341.6	350.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	252.3	279.1	9 years
Income Taxes Subject to Flow Through	(69.7)	(62.8)	28 years
Total Income Tax Related Regulatory Liabilities	524.2	566.8	
Total Regulatory Liabilities Approved for Payment	1,090.7	1,221.0	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,090.9	$ 1,221.2	

(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.

	PSO		
	December 31,		Remaining Recovery Period
	2019	2018	
Regulatory Assets:	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Oklaunion Power Station Accelerated Depreciation	$ 27.4	$ 5.5	
Total Regulatory Assets Currently Earning a Return	27.4	5.5	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	7.2	—	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.5	
Total Regulatory Assets Currently Not Earning a Return	7.2	0.5	
Total Regulatory Assets Pending Final Regulatory Approval	34.6	6.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	167.0	153.4	21 years
Meter Replacement Costs	30.2	34.3	8 years
Environmental Control Projects	27.8	29.2	21 years
Storm-Related Costs	21.3	31.1	3 years
Red Rock Generating Facility	8.4	8.6	37 years
Other Regulatory Assets Approved for Recovery	0.6	0.5	various
Total Regulatory Assets Currently Earning a Return	255.3	257.1	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	73.4	84.3	11 years
Unamortized Loss on Reacquired Debt	6.5	4.3	15 years
Peak Demand Reduction/Energy Efficiency	—	6.3	
Other Regulatory Assets Approved for Recovery	5.4	11.0	various
Total Regulatory Assets Currently Not Earning a Return	85.3	105.9	
Total Regulatory Assets Approved for Recovery	340.6	363.0	
Total Noncurrent Regulatory Assets	$ 375.2	$ 369.0	

Regulatory Liabilities:	PSO December 31, 2019	PSO December 31, 2018	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ 63.9	$ 20.1	1 year
Total Current Regulatory Liabilities	$ 63.9	$ 20.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 286.8	$ 276.8	(b)
Total Regulatory Liabilities Currently Paying a Return	286.8	276.8	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	51.5	51.5	25 years
Other Regulatory Liabilities Approved for Payment	4.7	2.5	various
Total Regulatory Liabilities Currently Not Paying a Return	56.2	54.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	405.8	415.2	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	96.3	126.4	5 years
Income Taxes Subject to Flow Through	(7.9)	(7.7)	24 years
Total Income Tax Related Regulatory Liabilities	494.2	533.9	
Total Regulatory Liabilities Approved for Payment	837.2	864.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 837.2	$ 864.7	

(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) Refunded using ARAM.

	SWEPCo		
	December 31,		Remaining Recovery Period
	2019	2018	
Regulatory Assets:	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 4.9	$ 18.8	1 year
Total Current Regulatory Assets	$ 4.9	$ 18.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant, Louisiana	$ 35.2	$ 50.3	
Other Regulatory Assets Pending Final Regulatory Approval	0.2	0.3	
Total Regulatory Assets Currently Earning a Return	35.4	50.6	
Regulatory Assets Currently Not Earning a Return			
Asset Retirement Obligation - Louisiana	7.2	5.3	
Rate Case Expense - Texas	1.0	4.9	
Other Regulatory Assets Pending Final Regulatory Approval	2.7	3.6	
Total Regulatory Assets Currently Not Earning a Return	10.9	13.8	
Total Regulatory Assets Pending Final Regulatory Approval	46.3	64.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant, Arkansas	15.1	—	23 years
Environmental Controls Projects	13.2	14.2	13 years
Other Regulatory Assets Approved for Recovery	8.9	7.2	various
Total Regulatory Assets Currently Earning a Return	37.2	21.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	102.6	108.4	11 years
Plant Retirement Costs - Unrecovered Plant, Texas	16.6	17.1	22 years
Unamortized Loss on Reacquired Debt	6.6	7.4	24 years
Rate Case Expense - Arkansas	5.2	0.8	5 years
Other Regulatory Assets Approved for Recovery	7.9	11.3	various
Total Regulatory Assets Currently Not Earning a Return	138.9	145.0	
Total Regulatory Assets Approved for Recovery	176.1	166.4	
Total Noncurrent Regulatory Assets	$ 222.4	$ 230.8	

(a) December 31, 2019 amount includes Arkansas jurisdiction. December 31, 2018 amount includes Arkansas and Louisiana jurisdictions.

	SWEPCo		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	2019	2018	
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return (a)	$ 13.6	$ 11.1	1 year
Total Current Regulatory Liabilities	$ 13.6	$ 11.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (b)			
Excess ADIT Associated with Certain Depreciable Property	$ 297.0	$ 280.1	
Excess ADIT that is Not Subject to Rate Normalization Requirements	22.7	26.9	
Total Regulatory Liabilities Pending Final Regulatory Determination	319.7	307.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	453.4	437.8	(c)
Other Regulatory Liabilities Approved for Payment	2.8	2.5	various
Total Regulatory Liabilities Currently Paying a Return	456.2	440.3	
Regulatory Liabilities Currently Not Paying a Return			
Peak Demand Reduction/Energy Efficiency	6.0	2.5	2 years
Deferred Investment Tax Credits	3.1	4.5	12 years
Other Regulatory Liabilities Approved for Payment	1.7	2.4	various
Total Regulatory Liabilities Currently Not Paying a Return	10.8	9.4	
Income Tax Related Regulatory Liabilities (b)			
Excess ADIT Associated with Certain Depreciable Property	339.4	370.5	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	27.8	54.3	1 year
Income Taxes Subject to Flow Through	(261.6)	(258.5)	28 years
Total Income Tax Related Regulatory Liabilities	105.6	166.3	
Total Regulatory Liabilities Approved for Payment	572.6	616.0	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 892.3	$ 923.0	

(a) December 31, 2019 amount includes Texas and Louisiana jurisdictions. December 31, 2018 amount includes Texas jurisdiction.
(b) 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.
(c) Relieved as removal costs are incurred.
(d) 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, 2019:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,047.0	$ 1,105.0	$ 234.4	$ 111.4	$ 2,497.8
Energy and Capacity Purchase Contracts	227.8	353.2	273.5	1,080.0	1,934.5
Total	$ 1,274.8	$ 1,458.2	$ 507.9	$ 1,191.4	$ 4,432.3

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 415.3	$ 369.2	$ 4.6	$ 0.3	$ 789.4
Energy and Capacity Purchase Contracts	35.4	72.1	73.7	275.5	456.7
Total	$ 450.7	$ 441.3	$ 78.3	$ 275.8	$ 1,246.1

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 299.8	$ 340.7	$ 211.6	$ 67.2	$ 919.3
Energy and Capacity Purchase Contracts	151.0	340.5	60.4	289.2	841.1
Total	$ 450.8	$ 681.2	$ 272.0	$ 356.4	$ 1,760.4

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 29.0	$ 58.6	$ 58.8	$ 302.5	$ 448.9

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 52.3	$ 42.8	$ —	$ —	$ 95.1
Energy and Capacity Purchase Contracts	93.0	132.3	65.2	193.3	483.8
Total	$ 145.3	$ 175.1	$ 65.2	$ 193.3	$ 578.9

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 130.4	$ 147.4	$ 4.5	$ —	$ 282.3
Energy and Capacity Purchase Contracts	14.0	12.5	8.4	8.4	43.3
Total	$ 144.4	$ 159.9	$ 12.9	$ 8.4	$ 325.6

(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, 2019, 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 six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2019 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 206.8	January 2020 to December 2020
AEP Texas	2.2	July 2020
OPCo	1.6	April 2020 to September 2020

Guarantees of Equity Method Investees (Applies to AEP)

In April 2019, AEP acquired Sempra Renewables LLC. See "Acquisitions" section of Note 7 for additional information.

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, 2019, 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" 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, 2019, APCo, OPCo and SWEPCo are named as a Potentially Responsible Party (PRP) for one, three, and one 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 three sites under state law. 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.

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, 2019, 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 2,288 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 $7 million, $8 million and $9 million for the years ended December 31, 2019, 2018 and 2017, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2019 and 2018, the total decommissioning trust fund balances were $2.7 billion and $2.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from customers. 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, 2019 and 2018, fees and related interest of $280 million and $274 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 $323 million and $317 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 $8 million, $11 million and $22 million in 2019, 2018 and 2017, 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, 2019 and 2018, I&M deferred $24 million and $8 million, respectively, in Prepayments and Other Current Assets and $1 million and $23 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 SNF 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 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 $47 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 $13.9 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 $275 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 $13.5 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 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 by the U.S. District Court for the Southern District of Ohio 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.

In 2017, 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.

Thereafter, 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. 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. The consent decree was modified based on an agreement among the parties in July 2019. As part of the modification to the consent decree, I&M agreed to provide an additional $7.5 million to citizens' groups and the states for environmental mitigation projects. As joint owners in the Rockport Plant, the $7.5 million payment was shared between AEGCo and I&M based on the joint ownership agreement. The district court entered a stay that expired in February 2020. Settlement negotiations are continuing, and the parties filed a joint proposed case schedule in February 2020. See "Modification of the New Source Review 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 cannot determine a range of potential losses that is reasonably possible of occurring.

Patent Infringement Complaint

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint seeks injunctive relief and damages. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and offering an opportunity to appeal those determinations. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

7. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

2019

Sempra Renewables LLC (Generation & Marketing Segment)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. This acquisition is part of AEP's strategy to grow its renewable generation portfolio and to diversify generation resources. AEP paid $580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $404 million as of the acquisition date (which includes $364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of $135 million. The purchase price was allocated as follows:

Purchase Price Allocation of Sempra Renewables LLC at Acquisition Date - April 22nd, 2019

Assets:			Liabilities and Equity:			Net Purchase Price	
			(in millions)				
Current Assets	$	8.8	Current Liabilities	$	12.9		
Property, Plant and Equipment		238.1	Asset Retirement Obligations		5.7		
Investment in Joint Ventures		404.0	**Total Liabilities**		18.6		
Other Noncurrent Assets		82.9	Noncontrolling Interest		134.8		
Total Assets	$	733.8	**Liabilities and Noncontrolling Interest**	$	153.4	$	580.4

Management allocated the purchase price based upon the relative fair value of the assets acquired and noncontrolling interests assumed. The fair value of the primary assets acquired and the noncontrolling interests assumed was determined using a discounted cash flow method under the income approach. The key input assumptions utilized in the determination of the fair value of these assets were the pricing and terms of the existing PPAs, forecasted market power prices, expected wind farm net capacity and discount rates reflecting risk inherent in the future cash flows and future power prices. Estimating forecasted market power prices involved determining the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third-party market participant assumptions. The expected wind farm net capacity was developed by evaluating each wind farm's historical and expected generation against historical generation of comparable wind farms in the same locations. Discount rates were evaluated by considering the cost of capital of comparable businesses. Additional key input assumptions for the fair value of the noncontrolling interests include the terms of the limited liability company agreements that dictate the sharing of the tax attributes and cash flows associated with the tax equity partnerships. Under the accounting rules for acquisitions, AEP has one year to finalize the purchase price allocation, including working capital adjustments and other closing adjustments.

Upon closing of the purchase, Sempra Renewables LLC was legally renamed AEP Wind Holdings LLC. AEP Wind Holdings LLC develops, owns and operates, or holds interests in, wind generation facilities in the United States. The operating wind generation portfolio includes seven wind farms. Five wind farms are jointly-owned with BP Wind Energy, and two wind farms are consolidated by AEP and are tax equity partnerships with nonaffiliated noncontrolling interests. All seven wind farms have long-term PPAs for 100% of their energy production. One of the joint venture wind farms has PPAs with I&M and OPCo for a portion of its energy production which totaled $9 million and $17 million, respectively, for the year ended December 31, 2019. Another joint venture wind farm has a PPA with SWEPCo for a portion of its energy production which totaled $10 million of purchased electricity for the year ended December 31, 2019. The PPAs with I&M, OPCo and SWEPCo were executed prior to the acquisition of the wind farms and will be accounted for in accordance with the accounting guidance for "Related Parties."

Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of December 31, 2019, the maximum potential amount of future payments associated with these guarantees was $175 million, with the last guarantee expiring in December 2037. The liability recorded associated with these guarantees was $34 million as of December 31, 2019.

The acquired business contributed revenues and net income to AEP that were not material for the period April 22, 2019 to December 31, 2019. The pro-forma revenue and net income related to the acquisition of Sempra Renewables LLC were not material for the year ended December 31, 2019.

See Note 17 - Variable Interest Entities and Equity Method Investments for additional information related to the purchased wind farms.

Santa Rita East (Generation & Marketing Segment)

In July 2019, AEP acquired a 75% interest, or 227 MWs, in Santa Rita East for approximately $356 million. In accordance with the accounting guidance for "Business Combinations," management determined that the acquisition of Santa Rita East represents an asset acquisition. Additionally, and in accordance with the accounting guidance for "Consolidation," management concluded that Santa Rita East is a VIE. As a result, to account for the initial consolidation of Santa Rita East, management applied the acquisition method by allocating the purchase price based on the relative fair value of the assets acquired and noncontrolling interest assumed. The fair value of the primary assets acquired and the noncontrolling interest assumed was determined using the market approach. The key input assumptions were the transaction price paid for AEP's interest in Santa Rita East and recent third-party market transactions for similar wind farms. See "Santa Rita East" section of Note 17 for additional information.

DISPOSITIONS

<u>2017</u>

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.

IMPAIRMENTS

2019

2019 Texas Base Rate Case (Transmission and Distribution Segment) (Applies to AEP and AEP Texas)

In December 2019, AEP Texas recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statements of income due to regulatory disallowances in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 for additional information.

Virginia Jurisdictional Book Value of Retired Coal-Fired Plants (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)

In December 2019, based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation. This expense is recorded in Asset Impairments and Other Related Charges on the statements of income. See "Virginia Legislation Affecting Earnings Reviews" section of Note 4 for additional information.

Merchant Generating Assets (Generation & Marketing Segment)

Due to a significant increase in the asset retirement costs recorded in December 2019 for the Ash Pond Complex at Conesville Plant, AEP performed an impairment analysis on Conesville Plant in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one and step two of the impairment analysis using a cash flow model for the estimated useful life of Conesville Plant 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. The step two analysis resulted in a fair value determination for Conesville Plant of $0 and AEP recorded a $31 million pretax impairment, equal to the net book value of the plant, in Asset Impairments and Other Related Charges on AEP's statements of income in the fourth quarter of 2019.

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 Asset Impairments and Other Related Charges 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.

Reconstruction activities at Racine are currently estimated to be completed in the first half of 2020. 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 book value once complete. Future revisions in cost estimates or delays in completion could result in additional losses which could reduce future net income and cash flows and impact financial condition.

<u>2017</u>

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"). 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.

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 benefit 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	**2019**	**2018**	**2019**	**2018**
Discount Rate	3.25%	4.30%	3.30%	4.30%
Interest Crediting Rate	4.00%	4.00%	NA	NA

NA Not applicable.

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	**2019**	**2018**
AEP	4.95%	4.85%
AEP Texas	5.00%	4.95%
APCo	4.80%	4.75%
I&M	4.95%	4.90%
OPCo	5.15%	5.00%
PSO	5.05%	4.90%
SWEPCo	4.90%	4.85%

(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 2019, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% 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	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Discount Rate	4.30%	3.65%	4.05%	4.30%	3.60%	4.10%
Interest Crediting Rate	4.00%	4.00%	4.00%	NA	NA	NA
Expected Return on Plan Assets	6.25%	6.00%	6.00%	6.25%	6.00%	6.75%

NA Not applicable.

	Pension Plans		
	Year Ended December 31,		
Assumption – Rate of Compensation Increase (a)	**2019**	**2018**	**2017**
AEP	4.95%	4.85%	4.80%
AEP Texas	5.00%	4.95%	4.90%
APCo	4.75%	4.75%	4.60%
I&M	4.95%	4.90%	4.85%
OPCo	5.20%	5.00%	4.95%
PSO	5.05%	4.90%	4.90%
SWEPCo	4.90%	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.

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	**2019**	**2018**
Initial	6.00%	6.25%
Ultimate	4.50%	5.00%
Year Ultimate Reached	2026	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, 2019, 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, 2019, the pension plans had an actuarial loss due to a decrease in the discount rate, partially offset by updates to the mortality table. For the year ended December 31, 2019, the OPEB plans had an actuarial loss due to a decrease in the discount rate and an update to the persistency assumption, partially offset by an update to the projected per capita cost assumption as well as savings resulting from legislation signed in December 2019 which eliminated two Affordable Care Act taxes. 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. 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	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 4,810.3	$ 5,215.8	$ 1,194.5	$ 1,332.0
Service Cost	95.5	97.6	9.5	11.6
Interest Cost	204.4	187.8	50.5	47.4
Actuarial (Gain) Loss	493.6	(306.3)	58.8	(100.1)
Plan Amendments	0.2	—	(11.0)	—
Benefit Payments	(367.2)	(384.6)	(113.0)	(133.6)
Participant Contributions	—	—	35.5	36.5
Medicare Subsidy	—	—	0.6	0.7
Benefit Obligation as of December 31,	$ 5,236.8	$ 4,810.3	$ 1,225.4	$ 1,194.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,695.9	$ 5,174.1	$ 1,534.2	$ 1,732.5
Actual Gain (Loss) on Plan Assets	681.1	(104.9)	321.0	(118.3)
Company Contributions (a)	5.6	11.3	4.1	17.1
Participant Contributions	—	—	35.5	36.5
Benefit Payments	(367.2)	(384.6)	(113.0)	(133.6)
Fair Value of Plan Assets as of December 31,	$ 5,015.4	$ 4,695.9	$ 1,781.8	$ 1,534.2
Funded (Underfunded) Status as of December 31,	$ (221.4)	$ (114.4)	$ 556.4	$ 339.7

(a) AEP did not make contributions to the qualified pension plan in 2019 or 2018. Contributions to the nonqualified pension plans were $6 million and $11 million for the years ended December 31, 2019 and 2018, respectively.

AEP	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 590.8	$ 392.2
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.1)	(5.7)	(2.6)	(2.8)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(215.3)	(108.7)	(31.8)	(49.7)
Funded (Underfunded) Status	$ (221.4)	$ (114.4)	$ 556.4	$ 339.7

AEP Texas	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 409.3	$ 441.3	$ 95.9	$ 107.1
Service Cost	8.6	9.2	0.8	0.9
Interest Cost	17.5	16.0	4.0	3.8
Actuarial (Gain) Loss	40.1	(20.9)	3.9	(8.3)
Plan Amendments	—	—	(0.9)	—
Benefit Payments	(34.3)	(36.3)	(8.8)	(10.7)
Participant Contributions	—	—	2.9	3.1
Benefit Obligation as of December 31,	$ 441.2	$ 409.3	$ 97.8	$ 95.9
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 410.7	$ 455.9	$ 129.9	$ 147.3
Actual Gain (Loss) on Plan Assets	58.3	(9.3)	24.0	(14.6)
Company Contributions	0.4	0.4	0.1	4.8
Participant Contributions	—	—	2.9	3.1
Benefit Payments	(34.3)	(36.3)	(8.8)	(10.7)
Fair Value of Plan Assets as of December 31,	$ 435.1	$ 410.7	$ 148.1	$ 129.9
Funded (Underfunded) Status as of December 31,	$ (6.1)	$ 1.4	$ 50.3	$ 34.0

AEP Texas	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ 5.2	$ 50.3	$ 34.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(5.7)	(3.4)	—	—
Funded (Underfunded) Status	$ (6.1)	$ 1.4	$ 50.3	$ 34.0

APCo	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 603.1	$ 665.0	$ 205.5	$ 236.5
Service Cost	9.4	9.3	1.0	1.1
Interest Cost	25.2	23.5	8.7	8.2
Actuarial (Gain) Loss	52.9	(49.2)	4.7	(21.9)
Plan Amendments	—	—	(1.7)	—
Benefit Payments	(43.4)	(45.5)	(20.8)	(24.7)
Participant Contributions	—	—	5.9	6.1
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 647.2	$ 603.1	$ 203.5	$ 205.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 593.3	$ 651.7	$ 238.4	$ 273.4
Actual Gain (Loss) on Plan Assets	87.1	(12.9)	45.3	(18.7)
Company Contributions	—	—	2.2	2.3
Participant Contributions	—	—	5.9	6.1
Benefit Payments	(43.4)	(45.5)	(20.8)	(24.7)
Fair Value of Plan Assets as of December 31,	$ 637.0	$ 593.3	$ 271.0	$ 238.4
Funded (Underfunded) Status as of December 31,	$ (10.2)	$ (9.8)	$ 67.5	$ 32.9

	Pension Plans		OPEB	
	December 31,			
APCo	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 92.0	$ 62.3
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.0)	(2.1)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(10.2)	(9.8)	(22.5)	(27.3)
Funded (Underfunded) Status	$ (10.2)	$ (9.8)	$ 67.5	$ 32.9

I&M	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 567.0	$ 624.3	$ 138.3	$ 153.5
Service Cost	13.4	13.6	1.4	1.6
Interest Cost	23.8	22.1	5.8	5.4
Actuarial (Gain) Loss	49.8	(53.9)	8.1	(10.6)
Plan Amendments	—	—	(1.5)	—
Benefit Payments	(37.9)	(39.1)	(13.6)	(16.2)
Participant Contributions	—	—	4.4	4.5
Medicare Subsidy	—	—	—	0.1
Benefit Obligation as of December 31,	$ 616.1	$ 567.0	$ 142.9	$ 138.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 583.8	$ 636.7	$ 187.3	$ 211.1
Actual Gain (Loss) on Plan Assets	84.6	(13.8)	38.2	(12.1)
Company Contributions	—	—	—	—
Participant Contributions	—	—	4.4	4.5
Benefit Payments	(37.9)	(39.1)	(13.6)	(16.2)
Fair Value of Plan Assets as of December 31,	$ 630.5	$ 583.8	$ 216.3	$ 187.3
Funded Status as of December 31,	$ 14.4	$ 16.8	$ 73.4	$ 49.0

	Pension Plans		OPEB	
	December 31,			
I&M	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 15.8	$ 18.0	$ 73.4	$ 49.0
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.4)	(1.2)	—	—
Funded Status	$ 14.4	$ 16.8	$ 73.4	$ 49.0

OPCo	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 453.9	$ 501.1	$ 129.5	$ 144.3
Service Cost	7.9	7.7	0.8	0.9
Interest Cost	19.1	17.7	5.5	5.1
Actuarial (Gain) Loss	40.5	(36.6)	4.9	(9.4)
Plan Amendments	—	—	(1.2)	—
Benefit Payments	(33.6)	(36.0)	(13.5)	(15.8)
Participant Contributions	—	—	4.1	4.3
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 487.8	$ 453.9	$ 130.2	$ 129.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 466.1	$ 509.1	$ 175.4	$ 198.5
Actual Gain (Loss) on Plan Assets	66.6	(7.0)	31.1	(11.6)
Participant Contributions	—	—	4.1	4.3
Benefit Payments	(33.6)	(36.0)	(13.5)	(15.8)
Fair Value of Plan Assets as of December 31,	$ 499.1	$ 466.1	$ 197.1	$ 175.4
Funded Status as of December 31,	$ 11.3	$ 12.2	$ 66.9	$ 45.9

	Pension Plans		**OPEB**	
	December 31,			
OPCo	**2019**	**2018**	**2019**	**2018**
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 11.7	$ 12.6	$ 66.9	$ 45.9
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.4)	(0.4)	—	—
Funded Status	$ 11.3	$ 12.2	$ 66.9	$ 45.9

PSO	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 253.8	$ 276.6	$ 62.3	$ 69.4
Service Cost	6.5	7.0	0.6	0.7
Interest Cost	10.6	9.9	2.6	2.5
Actuarial (Gain) Loss	16.8	(18.9)	3.8	(5.6)
Plan Amendments	—	—	(0.7)	—
Benefit Payments	(20.2)	(20.8)	(5.9)	(6.7)
Participant Contributions	—	—	2.0	2.0
Benefit Obligation as of December 31,	$ 267.5	$ 253.8	$ 64.7	$ 62.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 261.2	$ 287.8	$ 84.3	$ 95.5
Actual Gain (Loss) on Plan Assets	34.7	(5.9)	17.6	(9.2)
Company Contributions	0.5	0.1	—	2.7
Participant Contributions	—	—	2.0	2.0
Benefit Payments	(20.2)	(20.8)	(5.9)	(6.7)
Fair Value of Plan Assets as of December 31,	$ 276.2	$ 261.2	$ 98.0	$ 84.3
Funded Status as of December 31,	$ 8.7	$ 7.4	$ 33.3	$ 22.0

	Pension Plans		OPEB	
	December 31,			
PSO	2019	2018	2019	2018
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 10.6	$ 9.7	$ 33.3	$ 22.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.2)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.8)	(2.1)	—	—
Funded Status	$ 8.7	$ 7.4	$ 33.3	$ 22.0

SWEPCo	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 291.4	$ 314.6	$ 72.7	$ 80.3
Service Cost	8.6	9.3	0.8	0.9
Interest Cost	12.4	11.3	3.1	2.8
Actuarial (Gain) Loss	25.5	(19.2)	6.0	(5.9)
Plan Amendments	—	—	(0.8)	—
Benefit Payments	(23.7)	(24.6)	(6.6)	(7.7)
Participant Contributions	—	—	2.2	2.3
Benefit Obligation as of December 31,	$ 314.2	$ 291.4	$ 77.4	$ 72.7
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 281.0	$ 311.7	$ 98.5	$ 110.4
Actual Gain (Loss) on Plan Assets	39.5	(7.3)	23.1	(9.2)
Company Contributions	0.1	1.2	—	2.7
Participant Contributions	—	—	2.2	2.3
Benefit Payments	(23.7)	(24.6)	(6.6)	(7.7)
Fair Value of Plan Assets as of December 31,	$ 296.9	$ 281.0	$ 117.2	$ 98.5
Funded (Underfunded) Status as of December 31,	$ (17.3)	$ (10.4)	$ 39.8	$ 25.8

	Pension Plans		OPEB	
	December 31,			
SWEPCo	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 39.8	$ 25.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.2)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(17.2)	(10.2)	—	—
Funded (Underfunded) Status	$ (17.3)	$ (10.4)	$ 39.8	$ 25.8

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

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

AEP	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Net Actuarial Loss	$ 1,406.2	$ 1,355.2	$ 225.8	$ 419.8
Prior Service Cost (Credit)	0.2	—	(285.7)	(347.2)
Recorded as				
Regulatory Assets	$ 1,351.8	$ 1,267.9	$ (46.8)	$ 52.5
Deferred Income Taxes	11.5	18.4	(2.7)	4.2
Net of Tax AOCI	43.1	68.9	(10.4)	15.9

AEP	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 108.6	$ 88.8	$ (171.9)	$ 120.4
Amortization of Actuarial Loss	(57.6)	(87.8)	(22.1)	(10.5)
Prior Service (Credit) Cost	0.2	—	(7.6)	—
Amortization of Prior Service Credit	—	—	69.1	69.1
Change for the Year Ended December 31,	$ 51.2	$ 1.0	$ (132.5)	$ 179.0

AEP Texas	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Net Actuarial Loss	$ 184.7	$ 182.0	$ 23.5	$ 38.0
Prior Service Credit	—	—	(24.2)	(29.5)
Recorded as				
Regulatory Assets	$ 172.2	$ 168.2	$ (0.2)	$ 8.7
Deferred Income Taxes	2.7	2.9	(0.1)	—
Net of Tax AOCI	9.8	10.9	(0.4)	(0.2)

AEP Texas	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 7.6	$ 14.0	$ (12.7)	$ 14.9
Amortization of Actuarial Loss	(4.9)	(7.2)	(1.8)	(0.8)
Prior Service Credit	—	—	(0.6)	—
Amortization of Prior Service Credit	—	—	5.9	5.9
Change for the Year Ended December 31,	$ 2.7	$ 6.8	$ (9.2)	$ 20.0

APCo

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 168.3	$ 172.2	$ 28.8	$ 58.9
Prior Service Credit	—	—	(41.6)	(50.4)
Recorded as				
Regulatory Assets	$ 166.3	$ 169.6	$ (5.5)	$ 2.6
Deferred Income Taxes	0.3	0.5	(1.5)	1.2
Net of Tax AOCI	1.7	2.1	(5.8)	4.7

APCo

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 3.1	$ 0.3	$ (26.4)	$ 12.8
Amortization of Actuarial Loss	(7.0)	(10.6)	(3.7)	(1.9)
Prior Service Credit	—	—	(1.3)	—
Amortization of Prior Service Credit	—	—	10.1	10.0
Change for the Year Ended December 31,	$ (3.9)	$ (10.3)	$ (21.3)	$ 20.9

I&M

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 76.0	$ 80.6	$ 32.7	$ 54.7
Prior Service Credit	—	—	(39.0)	(47.4)
Recorded as				
Regulatory Assets	$ 73.7	$ 78.4	$ (6.2)	$ 6.5
Deferred Income Taxes	0.5	0.5	—	0.2
Net of Tax AOCI	1.8	1.7	(0.1)	0.6

I&M

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 2.0	$ (4.5)	$ (19.3)	$ 13.9
Amortization of Actuarial Loss	(6.6)	(9.8)	(2.7)	(1.2)
Prior Service Credit	—	—	(1.0)	—
Amortization of Prior Service Credit	—	—	9.4	9.5
Change for the Year Ended December 31,	$ (4.6)	$ (14.3)	$ (13.6)	$ 22.2

OPCo

Components	Pension Plans December 31, 2019		Pension Plans December 31, 2018		OPEB December 31, 2019		OPEB December 31, 2018	
	(in millions)							
Net Actuarial Loss	$	178.7	$	180.7	$	17.2	$	35.5
Prior Service Credit		—		—		(28.6)		(34.7)
Recorded as								
Regulatory Assets	$	178.7	$	180.7	$	(11.4)	$	0.8

OPCo

Components	Pension Plans 2019		Pension Plans 2018		OPEB 2019		OPEB 2018	
	(in millions)							
Actuarial (Gain) Loss During the Year	$	3.3	$	(0.9)	$	(15.8)	$	14.0
Amortization of Actuarial Loss		(5.3)		(8.0)		(2.5)		(1.1)
Prior Service Credit		—		—		(0.8)		—
Amortization of Prior Service Credit		—		—		6.9		6.9
Change for the Year Ended December 31,	$	(2.0)	$	(8.9)	$	(12.2)	$	19.8

PSO

Components	Pension Plans December 31, 2019		Pension Plans December 31, 2018		OPEB December 31, 2019		OPEB December 31, 2018	
	(in millions)							
Net Actuarial Loss	$	73.0	$	77.6	$	18.2	$	28.3
Prior Service Credit		—		—		(17.8)		(21.6)
Recorded as								
Regulatory Assets	$	73.0	$	77.6	$	0.4	$	6.7

PSO

Components	Pension Plans 2019		Pension Plans 2018		OPEB 2019		OPEB 2018	
	(in millions)							
Actuarial (Gain) Loss During the Year	$	(1.7)	$	3.2	$	(8.9)	$	9.0
Amortization of Actuarial Loss		(2.9)		(4.4)		(1.2)		(0.5)
Prior Service Credit		—		—		(0.5)		—
Amortization of Prior Service Credit		—		—		4.3		4.3
Change for the Year Ended December 31,	$	(4.6)	$	(1.2)	$	(6.3)	$	12.8

SWEPCo	Pension Plans				OPEB			
	December 31,							
	2019		2018		2019		2018	
Components	(in millions)							
Net Actuarial Loss	$	97.8	$	97.4	$	21.1	$	33.9
Prior Service Credit		—		—		(21.6)		(26.2)
Recorded as								
Regulatory Assets	$	97.8	$	97.4	$	—	$	4.9
Deferred Income Taxes		—		—		—		0.7
Net of Tax AOCI		—		—		(0.5)		2.1

SWEPCo	Pension Plans				OPEB			
	2019		2018		2019		2018	
Components	(in millions)							
Actuarial (Gain) Loss During the Year	$	3.8	$	5.5	$	(11.4)	$	9.8
Amortization of Actuarial Loss		(3.4)		(5.5)		(1.4)		(0.6)
Prior Service Credit		—		—		(0.6)		—
Amortization of Prior Service Credit		—		—		5.2		5.2
Change for the Year Ended December 31,	$	0.4	$	—	$	(8.2)	$	14.4

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	2019	2018	2019	2018
AEP Texas	8.7%	8.7%	8.3%	8.5%
APCo	12.7%	12.6%	15.2%	15.5%
I&M	12.6%	12.4%	12.1%	12.2%
OPCo	10.0%	9.9%	11.1%	11.4%
PSO	5.5%	5.6%	5.5%	5.5%
SWEPCo	5.9%	6.0%	6.6%	6.4%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 387.8	$ —	$ —	$ —	$ 387.8	7.8 %
International	609.1	—	—	—	609.1	12.1 %
Common Collective Trusts (c)	—	—	—	547.3	547.3	10.9 %
Subtotal – Equities	996.9	—	—	547.3	1,544.2	30.8 %
Fixed Income (a):						
United States Government and Agency Securities	(5.8)	1,248.6	—	—	1,242.8	24.8 %
Corporate Debt	—	1,143.7	—	—	1,143.7	22.8 %
Foreign Debt	—	211.6	—	—	211.6	4.2 %
State and Local Government	—	55.1	—	—	55.1	1.1 %
Other – Asset Backed	—	3.6	—	—	3.6	0.1 %
Subtotal – Fixed Income	(5.8)	2,662.6	—	—	2,656.8	53.0 %
Infrastructure (c)	—	—	—	85.8	85.8	1.7 %
Real Estate (c)	—	—	—	239.4	239.4	4.8 %
Alternative Investments (c)	—	—	—	448.3	448.3	8.9 %
Cash and Cash Equivalents (c)	—	24.4	—	37.2	61.6	1.2 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(20.7)	(20.7)	(0.4)%
Total	$ 991.1	$ 2,687.0	$ —	$ 1,337.3	$ 5,015.4	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, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 312.2	$ —	$ —	$ —	$ 312.2	17.5%
International	251.5	—	—	—	251.5	14.1%
Common Collective Trusts (b)	—	—	—	260.8	260.8	14.7%
Subtotal – Equities	563.7	—	—	260.8	824.5	46.3%
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	177.6	177.6	10.0%
United States Government and Agency Securities	(0.1)	214.4	—	—	214.3	12.0%
Corporate Debt	—	206.7	—	—	206.7	11.6%
Foreign Debt	—	35.5	—	—	35.5	2.0%
State and Local Government	58.8	14.8	—	—	73.6	4.1%
Other – Asset Backed	—	0.2	—	—	0.2	—%
Subtotal – Fixed Income	58.7	471.6	—	177.6	707.9	39.7%
Trust Owned Life Insurance:						
International Equities	—	60.2	—	—	60.2	3.4%
United States Bonds	—	151.6	—	—	151.6	8.5%
Subtotal – Trust Owned Life Insurance	—	211.8	—	—	211.8	11.9%
Cash and Cash Equivalents (b)	26.7	—	—	6.7	33.4	1.9%
Other – Pending Transactions and Accrued Income (a)	—	—	—	4.2	4.2	0.2%
Total	$ 649.1	$ 683.4	$ —	$ 449.3	$ 1,781.8	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, 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.

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	$ 4,929.0	$ 417.5	$ 627.3	$ 586.3	$ 464.2	$ 248.9	$ 291.9
Nonqualified Pension Plans	69.7	3.6	0.2	0.6	0.1	1.6	1.3
Total as of December 31, 2019	$ 4,998.7	$ 421.1	$ 627.5	$ 586.9	$ 464.3	$ 250.5	$ 293.2

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

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	$ 5,236.8	$ 441.2	$ 647.2	$ 1.5	$ 0.4	$ 1.9	$ 314.2
Fair Value of Plan Assets	5,015.4	435.1	637.0	—	—	—	296.9
Underfunded Projected Benefit Obligation as of December 31, 2019	$ (221.4)	$ (6.1)	$ (10.2)	$ (1.5)	$ (0.4)	$ (1.9)	$ (17.3)

	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)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 69.7	$ 3.6	$ 0.2	$ 0.6	$ 0.1	$ 1.6	$ 1.3
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2019	$ (69.7)	$ (3.6)	$ (0.2)	$ (0.6)	$ (0.1)	$ (1.6)	$ (1.3)

	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)

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 2020:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 6.1	$ 3.4
AEP Texas	0.4	0.1
APCo	—	2.0
I&M	—	—
OPCo	—	—
PSO	0.1	—
SWEPCo	0.1	—

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)			
2020	$ 378.1	$ 37.5	$ 45.8	$ 40.1	$ 36.2	$ 20.9	$ 24.0
2021	382.8	37.3	46.0	40.5	36.1	21.3	24.7
2022	380.5	35.9	45.7	42.5	35.7	21.2	25.2
2023	383.8	36.6	46.1	42.2	35.8	22.6	25.4
2024	382.9	36.3	46.8	42.8	34.0	21.5	25.8
Years 2025 to 2029, in Total	1,800.7	162.2	217.4	211.6	161.1	98.3	119.6

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2020	$ 126.3	$ 10.0	$ 22.5	$ 15.2	$ 14.8	$ 6.8	$ 7.5
2021	124.0	10.0	21.8	15.2	14.2	6.7	7.7
2022	125.2	10.4	21.6	15.5	14.4	6.9	8.0
2023	125.0	10.6	21.2	15.5	14.3	7.0	8.2
2024	124.6	10.7	21.1	15.4	14.1	7.1	8.4
Years 2025 to 2029, in Total	592.6	50.8	97.8	72.8	65.4	33.7	40.6

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2020	$ 0.2	$ —	$ 0.1	$ —	$ —	$ —	$ —
2021	0.3	—	0.2	—	—	—	—
2022	0.3	—	0.2	—	—	—	—
2023	0.3	—	0.1	—	—	—	—
2024	0.3	—	0.1	—	—	—	—
Years 2025 to 2029, in Total	1.4	—	0.6	—	—	—	—

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,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 95.5	$ 97.6	$ 96.5	$ 9.5	$ 11.6	$ 11.2
Interest Cost	204.4	187.8	203.1	50.5	47.4	59.3
Expected Return on Plan Assets	(296.0)	(290.3)	(284.8)	(93.7)	(102.2)	(101.3)
Amortization of Prior Service Cost (Credit)	—	—	1.0	(69.1)	(69.1)	(69.1)
Amortization of Net Actuarial Loss	57.6	85.2	82.8	22.1	10.5	36.7
Settlements	—	2.6	—	—	—	—
Net Periodic Benefit Cost (Credit)	61.5	82.9	98.6	(80.7)	(101.8)	(63.2)
Capitalized Portion	(38.6)	(41.1)	(39.9)	(3.8)	(4.9)	25.6
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 22.9	$ 41.8	$ 58.7	$ (84.5)	$ (106.7)	$ (37.6)

AEP Texas	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 8.6	$ 9.2	$ 8.6	$ 0.8	$ 0.9	$ 0.9
Interest Cost	17.5	16.0	17.1	4.0	3.8	4.9
Expected Return on Plan Assets	(25.8)	(25.6)	(25.0)	(7.8)	(8.6)	(8.8)
Amortization of Prior Service Cost	—	—	—	(5.9)	(5.9)	(5.8)
Amortization of Net Actuarial Loss	4.9	7.2	7.0	1.8	0.8	3.2
Net Periodic Benefit Cost (Credit)	5.2	6.8	7.7	(7.1)	(9.0)	(5.6)
Capitalized Portion	(4.5)	(4.8)	(4.0)	(0.4)	(0.5)	2.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 0.7	$ 2.0	$ 3.7	$ (7.5)	$ (9.5)	$ (2.7)

APCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 9.4	$ 9.3	$ 9.4	$ 1.0	$ 1.1	$ 1.1
Interest Cost	25.2	23.5	25.7	8.7	8.2	10.6
Expected Return on Plan Assets	(37.4)	(36.6)	(35.8)	(14.6)	(16.0)	(16.5)
Amortization of Prior Service Cost (Credit)	—	—	0.2	(10.1)	(10.0)	(10.1)
Amortization of Net Actuarial Loss	7.0	10.6	10.4	3.7	1.9	6.3
Net Periodic Benefit Cost (Credit)	4.2	6.8	9.9	(11.3)	(14.8)	(8.6)
Capitalized Portion	(4.0)	(3.8)	(4.0)	(0.4)	(0.5)	3.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 0.2	$ 3.0	$ 5.9	$ (11.7)	$ (15.3)	$ (5.1)

I&M	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 13.4	$ 13.6	$ 14.0	$ 1.4	$ 1.6	$ 1.6
Interest Cost	23.8	22.1	24.3	5.8	5.4	6.9
Expected Return on Plan Assets	(36.8)	(35.7)	(34.6)	(11.4)	(12.3)	(12.2)
Amortization of Prior Service Cost (Credit)	—	—	0.2	(9.4)	(9.5)	(9.4)
Amortization of Net Actuarial Loss	6.6	9.8	9.7	2.7	1.2	4.4
Net Periodic Benefit Cost (Credit)	7.0	9.8	13.6	(10.9)	(13.6)	(8.7)
Capitalized Portion	(3.4)	(5.6)	(5.5)	(0.4)	(0.7)	3.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.6	$ 4.2	$ 8.1	$ (11.3)	$ (14.3)	$ (5.2)

OPCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 7.9	$ 7.7	$ 7.5	$ 0.8	$ 0.9	$ 0.9
Interest Cost	19.1	17.7	19.4	5.5	5.1	6.7
Expected Return on Plan Assets	(29.3)	(28.8)	(27.9)	(10.8)	(11.7)	(11.9)
Amortization of Prior Service Cost (Credit)	—	—	0.1	(6.9)	(6.9)	(6.9)
Amortization of Net Actuarial Loss	5.3	8.0	7.8	2.5	1.1	4.3
Net Periodic Benefit Cost (Credit)	3.0	4.6	6.9	(8.9)	(11.5)	(6.9)
Capitalized Portion	(3.7)	(3.6)	(3.3)	(0.4)	(0.4)	3.3
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (0.7)	$ 1.0	$ 3.6	$ (9.3)	$ (11.9)	$ (3.6)

PSO	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 6.5	$ 7.0	$ 6.4	$ 0.6	$ 0.7	$ 0.7
Interest Cost	10.6	9.9	10.7	2.6	2.5	3.2
Expected Return on Plan Assets	(16.3)	(16.1)	(15.6)	(5.1)	(5.6)	(5.6)
Amortization of Prior Service Cost	—	—	—	(4.3)	(4.3)	(4.3)
Amortization of Net Actuarial Loss	2.9	4.4	4.3	1.2	0.5	2.0
Net Periodic Benefit Cost (Credit)	3.7	5.2	5.8	(5.0)	(6.2)	(4.0)
Capitalized Portion	(2.4)	(2.6)	(2.1)	(0.2)	(0.3)	1.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1.3	$ 2.6	$ 3.7	$ (5.2)	$ (6.5)	$ (2.6)

SWEPCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 8.6	$ 9.3	$ 8.7	$ 0.8	$ 0.9	$ 0.9
Interest Cost	12.4	11.3	12.3	3.1	2.8	3.6
Expected Return on Plan Assets	(17.7)	(17.3)	(17.0)	(5.9)	(6.4)	(6.3)
Amortization of Prior Service Cost (Credit)	—	—	0.1	(5.2)	(5.2)	(5.2)
Amortization of Net Actuarial Loss	3.4	5.1	4.9	1.4	0.6	2.3
Settlements	—	0.4	—	—	—	—
Net Periodic Benefit Cost (Credit)	6.7	8.8	9.0	(5.8)	(7.3)	(4.7)
Capitalized Portion	(2.9)	(3.1)	(2.7)	(0.3)	(0.3)	1.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.8	$ 5.7	$ 6.3	$ (6.1)	$ (7.6)	$ (3.3)

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	**2019**	**2018**	**2017**
	(in millions)		
AEP	$ 76.4	$ 71.8	$ 74.6
AEP Texas	5.9	5.7	6.0
APCo	7.5	7.5	7.4
I&M	11.0	10.5	10.7
OPCo	6.6	6.3	6.1
PSO	4.6	4.5	5.0
SWEPCo	6.2	5.9	6.0

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits negotiated with the UMWA 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, 2019 and 2018, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in 2015. The Rehabilitation Plan has been updated annually, most recently in April 2019.

The amounts contributed by AEP affiliates in 2019, 2018 and 2017 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, 2018. The contributions in 2019, 2018 and 2017 did not include 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 anticipated contributions toward its proportionate share of the plan's unfunded vested liabilities. As of December 31, 2019 and 2018, the liability balance was $20 million and $15 million, respectively. AEP recovers the estimated value of its 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, 2019, AEP recorded a regulatory asset on the balance sheets for $2 million and as of December 31, 2018, AEP recorded a regulatory liability on the balance sheets for $3 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

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

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, 2019, 2018 and 2017 and reportable segment balance sheet information as of December 31, 2019 and 2018.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2019							
Revenues from:							
External Customers	$ 9,245.7	$ 4,319.0	$ 260.2	$ 1,721.8	$ 14.7	$ —	$ 15,561.4
Other Operating Segments	121.4	163.5	813.0	135.8	81.1	(1,314.8)	—
Total Revenues	$ 9,367.1	$ 4,482.5	$ 1,073.2	$ 1,857.6	$ 95.8	$ (1,314.8)	$ 15,561.4
Asset Impairments and Other Related Charges	$ 92.9	$ 32.5	$ —	$ 31.0	$ —	$ —	$ 156.4
Depreciation and Amortization	1,447.0	789.5	183.4	69.5	0.6	24.5 (b)	2,514.5
Interest Expense	568.3	243.3	103.3	30.0	193.7	(66.1) (b)	1,072.5
Income Tax Expense (Benefit)	(97.7)	(25.2)	136.2	(53.8)	27.6	—	(12.9)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	3.0	—	72.8	(3.8)	0.1	—	72.1
Net Income (Loss)	$ 985.6	$ 451.0	$ 520.1	$ 104.1	$ (141.0)	$ —	$ 1,919.8
Gross Property Additions	$ 2,437.4	$ 2,074.3	$ 1,458.9	$ 1,005.1	$ 14.5	$ (20.4)	$ 6,969.8
Total Property, Plant and Equipment	$ 47,323.7	$ 19,773.3	$ 10,334.0	$ 1,650.8	$ 418.4	$ (354.5) (b)	$ 79,145.7
Accumulated Depreciation and Amortization	14,580.4	3,911.2	418.9	99.0	184.5	(186.4) (b)	19,007.6
Total Property, Plant and Equipment – Net	$ 32,743.3	$ 15,862.1	$ 9,915.1	$ 1,551.8	$ 233.9	$ (168.1) (b)	$ 60,138.1
Total Assets	$ 41,228.8	$ 18,757.5	$ 11,143.5	$ 3,123.8	$ 5,440.0 (c)	$ (3,801.3) (b) (d)	$ 75,892.3
Investments in Equity Method Investees	$ 41.7	$ 2.5	$ 787.5	$ 459.5	$ 65.4	$ —	$ 1,356.6
Long-term Debt Due Within One Year:							
Affiliated	$ 20.0	$ —	$ —	$ —	$ —	$ (20.0)	$ —
Nonaffiliated	704.7	392.2	—	—	501.8 (e)	—	1,598.7
Long-term Debt:							
Affiliated	39.0	—	—	—	—	(39.0)	—
Nonaffiliated	12,162.0	6,248.1	3,593.8	—	3,122.9 (e)	—	25,126.8
Total Long-term Debt	$ 12,925.7	$ 6,640.3	$ 3,593.8	$ —	$ 3,624.7	$ (59.0)	$ 26,725.5

2018	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 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 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
Equity Earnings of Unconsolidated Subsidiaries	2.7	—	68.7	0.5	1.2	—	73.1
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	—	21,648.2
Total Long-term Debt	$ 12,559.0	$ 5,597.9	$ 2,973.6	$ 32.0	$ 2,266.4 (e)	$ (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 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
Equity Earnings (Loss) of Unconsolidated Subsidiaries	$ (3.8)	$ —	$ 88.6	$ —	$ (2.4)	$ —	$ 82.4
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 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

(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 finance 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, 2019, 2018 and 2017 and reportable segment balance sheet information as of December 31, 2019 and 2018.

2019	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
		(in millions)				
Revenues from:						
External Customers	$ 214.6	$ —		$ —		$ 214.6
Sales to AEP Affiliates	806.7	—		—		806.7
Other Revenues	0.1	—		—		0.1
Total Revenues	$ 1,021.4	$ —		$ —		$ 1,021.4
Depreciation and Amortization	$ 176.0	$ —		$ —		$ 176.0
Interest Income	1.3	123.8		(122.1)	(a)	3.0
Allowance for Equity Funds Used During Construction	84.3	—		—		84.3
Interest Expense	97.4	122.1		(122.1)	(a)	97.4
Income Tax Expense	117.1	0.3		—		117.4
Net Income	$ 438.6	$ 1.1	(b)	$ —		$ 439.7
Gross Property Additions	$ 1,419.5	$ —		$ —		$ 1,419.5
Total Transmission Property	$ 9,893.2	$ —		$ —		$ 9,893.2
Accumulated Depreciation and Amortization	402.3	—		—		402.3
Total Transmission Property - Net	$ 9,490.9	$ —		$ —		$ 9,490.9
Notes Receivable - Affiliated	$ —	$ 3,427.3		$ (3,427.3)	(c)	$ —
Total Assets	$ 9,865.0	$ 3,519.1	(d)	$ (3,493.3)	(e)	$ 9,890.8
Total Long-Term Debt	$ 3,465.0	$ 3,427.3		$ (3,465.0)	(c)	$ 3,427.3

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	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 138.0	$ —	$ —	$ 138.0
Sales to AEP Affiliates	568.1	—	—	568.1
Other	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 (Benefit)	142.0	0.2	—	142.2
Net Income (Loss)	$ 270.4	$ 0.3 (b)	$ —	$ 270.7
Gross Property Additions	$ 1,522.5	$ —	$ —	$ 1,522.5
Total Assets	$ 7,086.9	$ 2,590.1 (d)	$ (2,594.9) (e)	$ 7,082.1

(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.

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.

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 and credit 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, 2019

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	365.9	—	61.0	26.8	7.1	14.9	4.4
Natural Gas	MMBtus	40.7	—	—	—	—	—	11.6
Heating Oil and Gasoline	Gallons	6.9	1.8	1.1	0.6	1.4	0.7	0.9
Interest Rate	USD	$ 140.1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 625.0	$ —	$ —	$ —	$ —	$ —	$ —

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 on Long-term Debt	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.

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 $5 million and $18 million as of December 31, 2019 and 2018, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $39 million and $4 million as of December 31, 2019 and 2018, 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, 2019 and 2018.

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, 2019

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	$ 513.9	$ 11.5	$ 6.5	$ 531.9	$ (359.1)	$ 172.8
Long-term Risk Management Assets	290.8	11.0	12.6	314.4	(47.8)	266.6
Total Assets	804.7	22.5	19.1	846.3	(406.9)	439.4
Current Risk Management Liabilities	424.5	72.3	—	496.8	(382.5)	114.3
Long-term Risk Management Liabilities	244.5	75.7	—	320.2	(58.4)	261.8
Total Liabilities	669.0	148.0	—	817.0	(440.9)	376.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 135.7	$ (125.5)	$ 19.1	$ 29.3	$ 34.0	$ 63.3

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

AEP Texas

Fair Value of Derivative Instruments
December 31, 2019

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

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)

APCo

Fair Value of Derivative Instruments
December 31, 2019

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	$ 124.4	$ (85.0)	$ 39.4
Long-term Risk Management Assets	0.9	(0.8)	0.1
Total Assets	125.3	(85.8)	39.5
Current Risk Management Liabilities	86.2	(84.3)	1.9
Long-term Risk Management Liabilities	0.7	(0.7)	—
Total Liabilities	86.9	(85.0)	1.9
Total MTM Derivative Contract Net Assets (Liabilities)	$ 38.4	$ (0.8)	$ 37.6

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

I&M

Fair Value of Derivative Instruments
December 31, 2019

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	$ 66.9	$ (57.1)	$ 9.8
Long-term Risk Management Assets	0.5	(0.4)	0.1
Total Assets	67.4	(57.5)	9.9
Current Risk Management Liabilities	55.2	(54.7)	0.5
Long-term Risk Management Liabilities	0.4	(0.4)	—
Total Liabilities	55.6	(55.1)	0.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ 11.8	$ (2.4)	$ 9.4

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

OPCo

Fair Value of Derivative Instruments
December 31, 2019

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	7.3	—	7.3
Long-term Risk Management Liabilities	96.3	—	96.3
Total Liabilities	103.6	—	103.6
Total MTM Derivative Contract Net Liabilities	$ (103.6)	$ —	$ (103.6)

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)

PSO

Fair Value of Derivative Instruments
December 31, 2019

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	$ 16.3	$ (0.5)	$ 15.8
Long-term Risk Management Assets	—	—	—
Total Assets	16.3	(0.5)	15.8
Current Risk Management Liabilities	0.5	(0.5)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.5	(0.5)	—
Total MTM Derivative Contract Net Assets	$ 15.8	$ —	$ 15.8

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

SWEPCo

Fair Value of Derivative Instruments
December 31, 2019

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	$ 6.5	$ (0.1)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.5	(0.1)	6.4
Current Risk Management Liabilities	2.0	(0.1)	1.9
Long-term Risk Management Liabilities	3.1	—	3.1
Total Liabilities	5.1	(0.1)	5.0
Total MTM Derivative Contract Net Assets	$ 1.4	$ —	$ 1.4

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

(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, 2019

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Vertically Integrated Utilities Revenues	$ 0.7	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	25.1	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	0.5	—	—	0.1
Purchased Electricity for Resale	1.9	—	1.6	0.1	—	—	—
Other Operation	(0.8)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)
Maintenance	(0.8)	(0.2)	(0.2)	(0.1)	(0.2)	(0.1)	(0.1)
Regulatory Assets (a)	(3.7)	0.7	0.3	0.3	(3.7)	1.2	(1.5)
Regulatory Liabilities (a)	102.6	—	2.4	24.5	10.1	34.6	26.6
Total Gain on Risk Management Contracts	$ 125.0	$ 0.3	$ 4.1	$ 25.2	$ 6.0	$ 35.6	$ 25.0

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

(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, 2019	**December 31, 2018**	**December 31, 2019**	**December 31, 2018**
	(in millions)			
Long-term Debt (a)	$ (510.8)	$ (478.3)	$ (14.5)	$ 17.4

(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,		
	2019	**2018**	**2017**
	(in millions)		
Gain (Loss) on Interest Rate Contracts:			
Gain (Loss) on Fair Value Hedging Instruments (a)	$ 31.9	$ (11.3)	$ (4.8)
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	(31.9)	11.3	4.8

(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 2019, 2018 and 2017, AEP applied cash flow hedging to outstanding power derivatives. During the years ended 2019, 2018 and 2017, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the years ended 2019, 2018 and 2017, AEP applied cash flow hedging to outstanding interest rate derivatives. During the years ended 2019 and 2017, 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.

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, 2019		December 31, 2018	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (103.5)	$ (11.5) (a)	$ (23.0)	$ (12.6)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	(51.7)	(2.1)	10.4	(1.1)

(a) Includes $4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC. See "Sempra Renewables LLC" section of Note 17 for additional information.

As of December 31, 2019 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 120 months and 132 months for commodity and interest rate hedges, respectively.

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

	December 31, 2019		December 31, 2018	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (3.4)	$ (1.1)	$ (4.4)	$ (1.1)
APCo	0.9	0.9	1.8	0.9
I&M	(9.9)	(1.6)	(11.5)	(1.6)
OPCo	—	—	1.0	1.0
PSO	1.1	1.0	2.1	1.0
SWEPCo	(1.8)	(1.5)	(3.3)	(1.5)

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, 2019 and 2018.

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, 2019		
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	$ 267.3	$ 3.7	$ 246.7
APCo	2.3	—	0.4
I&M	1.3	—	0.2
SWEPCo	5.1	—	5.1

	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

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 fair value of AEP's Equity Units (Level 1) are valued based on publicly traded securities issued by AEP.

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

	December 31,			
	2019		2018	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP (a)	$ 26,725.5	$ 30,172.0	$ 23,346.7	$ 24,093.9
AEP Texas	4,558.4	4,981.5	3,881.3	3,964.6
AEPTCo	3,427.3	3,868.0	2,823.0	2,782.4
APCo	4,363.8	5,253.1	4,062.6	4,473.3
I&M	3,050.2	3,453.8	3,035.4	3,070.2
OPCo	2,082.0	2,554.3	1,716.6	1,919.7
PSO	1,386.2	1,603.3	1,287.0	1,361.9
SWEPCo	2,655.6	2,927.9	2,713.4	2,670.2

(a) The fair value amount includes debt related to AEP's Equity Units issued in March 2019 and had a fair value of $871 million as of December 31, 2019. See "Equity Units" section of Note 14 for additional information.

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, 2019			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 214.7	$ —	$ —	$ 214.7
Fixed Income Securities – Mutual Funds (b)	123.2	0.1	—	123.3
Equity Securities – Mutual Funds	29.2	21.3	—	50.5
Total Other Temporary Investments	$ 367.1	$ 21.4	$ —	$ 388.5

Other Temporary Investments	December 31, 2018 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

(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, 2019	2018	2017
		(in millions)	
Proceeds from Investment Sales	$ 21.2	$ —	$ —
Purchases of Investments	45.0	3.1	14.2
Gross Realized Gains on Investment Sales	—	—	—
Gross Realized Losses on Investment Sales	0.4	—	—

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 and 2017, see Note 3 - Comprehensive Income.

Fair Value Measurements of Trust Assets for Decommissioning and SNF 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, 2019			2018		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
			(in millions)			
Cash and Cash Equivalents	$ 15.3	$ —	$ —	$ 22.5	$ —	$ —
Fixed Income Securities:						
United States Government	1,112.5	55.5	(6.1)	996.1	26.7	(7.1)
Corporate Debt	72.4	5.3	(1.6)	52.4	1.1	(1.9)
State and Local Government	7.6	0.7	(0.2)	8.6	0.6	(0.2)
Subtotal Fixed Income Securities	1,192.5	61.5	(7.9)	1,057.1	28.4	(9.2)
Equity Securities - Domestic (a)	1,767.9	1,144.4	—	1,395.3	766.3	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,975.7	$ 1,205.9	$ (7.9)	$ 2,474.9	$ 794.7	$ (9.2)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.1 billion and $784 million and unrealized losses of $5 million and $18 million as of December 31, 2019 and 2018, respectively. 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,		
	2019	2018	2017
		(in millions)	
Proceeds from Investment Sales	$ 1,473.0	$ 2,010.0	$ 2,256.3
Purchases of Investments	1,531.0	2,064.7	2,300.5
Gross Realized Gains on Investment Sales	76.5	47.5	200.7
Gross Realized Losses on Investment Sales	24.3	32.8	146.0

The base cost of fixed income securities was $1.1 billion and $1 billion as of December 31, 2019 and 2018, respectively. The base cost of equity securities was $623 million and $629 million as of December 31, 2019 and 2018, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2019 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 371.0
After 1 year through 5 years	386.2
After 5 years through 10 years	217.3
After 10 years	218.0
Total	$ 1,192.5

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, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 197.6	$ —	$ —	$ 17.1	$ 214.7
Fixed Income Securities – Mutual Funds	123.3	—	—	—	123.3
Equity Securities – Mutual Funds (b)	50.5	—	—	—	50.5
Total Other Temporary Investments	371.4	—	—	17.1	388.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	4.0	440.1	369.2	(404.5)	408.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	15.0	3.2	(6.7)	11.5
Interest Rate Hedges	—	4.6	—	—	4.6
Fair Value Hedges	—	14.5	—	—	14.5
Total Risk Management Assets	4.0	474.2	372.4	(411.2)	439.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	6.7	—	—	8.6	15.3
Fixed Income Securities:					
United States Government	—	1,112.5	—	—	1,112.5
Corporate Debt	—	72.4	—	—	72.4
State and Local Government	—	7.6	—	—	7.6
Subtotal Fixed Income Securities	—	1,192.5	—	—	1,192.5
Equity Securities – Domestic (b)	1,767.9	—	—	—	1,767.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,774.6	1,192.5	—	8.6	2,975.7
Total Assets	$ 2,150.0	$ 1,666.7	$ 372.4	$ (385.5)	$ 3,803.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 3.8	$ 450.0	$ 224.0	$ (438.8)	$ 239.0
Cash Flow Hedges:					
Commodity Hedges (c)	—	105.3	38.5	(6.7)	137.1
Total Risk Management Liabilities	$ 3.8	$ 555.3	$ 262.5	$ (445.5)	$ 376.1

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

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
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) (f)	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) (f)	$ 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

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 154.7	$ —	$ —	$ —	$ 154.7

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

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 23.5	$ —	$ —	$ —	$ 23.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	84.6	40.5	(85.6)	39.5
Total Assets	$ 23.5	$ 84.6	$ 40.5	$ (85.6)	$ 63.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 84.0	$ 2.8	$ (84.9)	$ 1.9

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

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 59.5	$ 8.0	$ (57.6)	$ 9.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	6.7	—	—	8.6	15.3
Fixed Income Securities:					
United States Government	—	1,112.5	—	—	1,112.5
Corporate Debt	—	72.4	—	—	72.4
State and Local Government	—	7.6	—	—	7.6
Subtotal Fixed Income Securities	—	1,192.5	—	—	1,192.5
Equity Securities - Domestic (b)	1,767.9	—	—	—	1,767.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,774.6	1,192.5	—	8.6	2,975.7
Total Assets	$ 1,774.6	$ 1,252.0	$ 8.0	$ (49.0)	$ 2,985.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 53.4	$ 2.2	$ (55.1)	$ 0.5

December 31, 2018

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
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

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 103.6	$ —	$ 103.6

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

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 16.3	$ (0.5)	$ 15.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.5	$ (0.5)	$ —

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

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 6.5	$ (0.1)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 5.1	$ (0.1)	$ 5.0

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

(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, 2019 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(7) million in 2020 and $(3) million in periods 2021-2023; Level 3 matures $96 million in 2020, $36 million in periods 2021-2023, $25 million in periods 2024-2025 and $(12) million in periods 2026-2032. 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, 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.

(g) Substantially comprised of power contracts for the Registrant Subsidiaries.

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, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	15.8	(13.9)	4.7	(0.9)	13.5	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(0.1)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(15.1)	—	—	—	—	—
Settlements	(117.6)	(42.5)	(13.0)	6.6	(23.0)	(9.6)
Transfers into Level 3 (d) (e)	(0.6)	(0.5)	(0.3)	—	—	—
Transfers out of Level 3 (e)	35.6	(0.7)	(0.4)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	60.7	37.5	5.9	(9.9)	15.8	2.7
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4

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) (a) (b)	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 (a)	9.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	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) (a) (b)	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 (a)	33.6	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(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

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Included in cash flow hedges on the statements of comprehensive income.
(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, 2019

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 296.7	$ 249.3	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 177.30	$ 31.31
Natural Gas Contracts	—	4.9	Discounted Cash Flow	Forward Market Price (b)	1.89	2.51	2.19
FTRs	75.7	8.3	Discounted Cash Flow	Forward Market Price (a)	(8.52)	9.34	0.42
Total	$ 372.4	$ 262.5					

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(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					

APCo

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 5.7	$ 2.6	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	34.8	0.2	Discounted Cash Flow	Forward Market Price	(0.14)	7.08	1.70
Total	$ 40.5	$ 2.8					

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(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					

I&M

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 3.4	$ 1.5	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	4.6	0.7	Discounted Cash Flow	Forward Market Price	(0.75)	4.07	0.74
Total	$ 8.0	$ 2.2					

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(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					

OPCo

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 103.6	Discounted Cash Flow	Forward Market Price	$ 29.23	$ 61.43	$ 42.46

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 99.4	Discounted Cash Flow	Forward Market Price	$ 26.29	$ 62.74	$ 42.50

PSO

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 16.3	$ 0.5	Discounted Cash Flow	Forward Market Price	$ (8.52)	$ 0.85	$ (2.31)

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 10.8	$ 1.3	Discounted Cash Flow	Forward Market Price	$(11.68)	$ 10.30	$ (1.40)

SWEPCo

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range		
	Assets	Liabilities			Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 4.9	Discounted Cash Flow	Forward Market Price (b)	$ 1.89	$ 2.51	$ 2.18
FTRs	6.5	0.2	Discounted Cash Flow	Forward Market Price (a)	(8.52)	0.85	(2.31)
Total	$ 6.5	$ 5.1					

December 31, 2018

	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range		
	Assets	Liabilities			Low	High	Weighted Average (c)
	(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					

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.
(c) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty 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, 2019 and 2018:

Uncertainty 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.

Income Tax Expense (Benefit)

The details of the Registrants' Income Tax Expense (Benefit) as reported are as follows:

Year Ended December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (7.4)	$ (31.8)	$ 23.7	$ 36.7	$ 48.1	$ (10.0)	$ 25.5	$ 6.9
Deferred	(77.1)	(23.5)	71.7	(125.6)	(53.5)	40.6	(23.6)	(8.6)
Deferred Investment Tax Credits	5.5	(1.2)	—	(0.5)	(3.6)	—	(2.4)	(1.4)
Total Federal	(79.0)	(56.5)	95.4	(89.4)	(9.0)	30.6	(0.5)	(3.1)
State and Local:								
Current	4.4	2.9	2.4	12.0	(2.4)	1.1	0.2	0.8
Deferred	59.3	—	19.6	(0.6)	0.8	3.2	5.4	(2.4)
Deferred Investment Tax Credits	2.4	—	—	—	—	—	2.4	—
Total State and Local	66.1	2.9	22.0	11.4	(1.6)	4.3	8.0	(1.6)
Income Tax Expense (Benefit)	$ (12.9)	$ (53.6)	$ 117.4	$ (78.0)	$ (10.6)	$ 34.9	$ 7.5	$ (4.7)

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)	$ 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	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)	$ 969.7	$ (23.4)	$ 142.2	$ 185.3	$ 81.4	$ 159.3	$ 50.1	$ 48.1

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,**		
	2019	**2018**	**2017**
		(in millions)	
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Less: Equity Earnings – Dolet Hills	(3.0)	(2.7)	—
Income Tax Expense (Benefit)	(12.9)	115.3	969.7
Pretax Income	$ 1,903.9	$ 2,043.9	$ 2,898.6
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 399.8	$ 429.2	$ 1,014.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	23.1	24.4	60.2
Investment Tax Credit Amortization	(13.0)	(20.2)	(18.8)
Production Tax Credits	(59.0)	(10.3)	—
State and Local Income Taxes, Net	52.2	19.7	54.7
Removal Costs	(20.7)	(19.8)	(32.7)
AFUDC	(37.1)	(29.4)	(37.4)
Valuation Allowance	—	—	(1.8)
Tax Reform Adjustments	—	(10.9)	(26.7)
Tax Adjustments	—	—	(35.8)
Tax Reform Excess ADIT Reversal	(353.2)	(257.2)	—
Other	(5.0)	(10.2)	(6.5)
Income Tax Expense (Benefit)	$ (12.9)	$ 115.3	$ 969.7
Effective Income Tax Rate	(0.7)%	5.6 %	33.5 %

AEP Texas	**Years Ended December 31,**		
	2019	**2018**	**2017**
		(in millions)	
Net Income	$ 178.3	$ 211.3	$ 310.5
Income Tax Expense (Benefit)	(53.6)	20.8	(23.4)
Pretax Income	$ 124.7	$ 232.1	$ 287.1
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 26.2	$ 48.7	$ 100.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.0	1.4	(0.5)
Investment Tax Credit Amortization	(1.2)	(2.3)	(1.5)
State and Local Income Taxes, Net	2.3	1.3	0.4
AFUDC	(3.2)	(4.2)	(3.9)
Parent Company Loss Benefit	(4.6)	(3.1)	—
Tax Reform Adjustments	—	(11.0)	(117.4)
Tax Adjustments	—	—	(4.2)
Tax Reform Excess ADIT Reversal	(73.4)	(11.8)	—
Other	(0.7)	1.8	3.2
Income Tax Expense (Benefit)	$ (53.6)	$ 20.8	$ (23.4)
Effective Income Tax Rate	(43.0)%	9.0 %	(8.2)%

AEPTCo

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 439.7	$ 315.9	$ 270.7
Income Tax Expense	117.4	84.1	142.2
Pretax Income	$ 557.1	$ 400.0	$ 412.9
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 117.0	$ 84.0	$ 144.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
AFUDC	(17.7)	(14.1)	(17.0)
State and Local Income Taxes, Net	17.4	12.6	13.1
Tax Reform Adjustments	—	—	0.6
Other	0.7	1.6	1.0
Income Tax Expense	$ 117.4	$ 84.1	$ 142.2
Effective Income Tax Rate	21.1 %	21.0 %	34.4 %

APCo

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 306.3	$ 367.8	$ 331.3
Income Tax Expense (Benefit)	(78.0)	(44.9)	185.3
Pretax Income	$ 228.3	$ 322.9	$ 516.6
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 47.9	$ 67.8	$ 180.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	11.7	8.5	18.0
State and Local Income Taxes, Net	9.0	9.1	3.5
Removal Costs	(6.1)	(9.6)	(12.4)
AFUDC	(5.2)	(4.3)	(5.0)
Parent Company Loss Benefit	(3.8)	(3.4)	(0.2)
Tax Reform Adjustments	—	0.1	4.3
Tax Reform Excess ADIT Reversal	(130.4)	(108.5)	—
Other	(1.1)	(4.6)	(3.7)
Income Tax Expense (Benefit)	$ (78.0)	$ (44.9)	$ 185.3
Effective Income Tax Rate	(34.2)%	(13.9)%	35.9 %

I&M

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 269.4	$ 261.3	$ 186.7
Income Tax Expense (Benefit)	(10.6)	29.1	81.4
Pretax Income	$ 258.8	$ 290.4	$ 268.1
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 54.3	$ 61.0	$ 93.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	6.3	(0.7)	11.4
Investment Tax Credit Amortization	(3.6)	(4.7)	(4.7)
State and Local Income Taxes, Net	(1.2)	13.4	(1.0)
Removal Costs	(11.5)	(8.0)	(13.3)
AFUDC	(4.1)	(2.5)	(5.6)
Parent Company Loss Benefit	(4.8)	(2.3)	—
Tax Adjustments	—	—	2.7
Tax Reform Adjustments	—	—	(2.9)
Tax Reform Excess ADIT Reversal	(42.5)	(25.8)	—
Other	(3.5)	(1.3)	1.0
Income Tax Expense (Benefit)	$ (10.6)	$ 29.1	$ 81.4
Effective Income Tax Rate	(4.1)%	10.0 %	30.4 %

OPCo

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 297.1	$ 325.5	$ 323.9
Income Tax Expense	34.9	24.0	159.3
Pretax Income	$ 332.0	$ 349.5	$ 483.2
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 69.7	$ 73.4	$ 169.1
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	(1.7)	2.6	7.6
State and Local Income Taxes, Net	3.4	4.2	4.4
AFUDC	(3.8)	(2.1)	(2.2)
Tax Reform Adjustments	—	—	(14.4)
Tax Reform Excess ADIT Reversal	(27.3)	(51.0)	—
Parent Company Loss Benefit	(4.9)	(5.5)	(0.2)
Other	(0.5)	2.4	(5.0)
Income Tax Expense	$ 34.9	$ 24.0	$ 159.3
Effective Income Tax Rate	10.5 %	6.9 %	33.0 %

PSO

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 137.6	$ 83.2	$ 72.0
Income Tax Expense	7.5	5.0	50.1
Pretax Income	$ 145.1	$ 88.2	$ 122.1
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 30.5	$ 18.5	$ 42.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	0.5	1.0	0.3
Investment Tax Credit Amortization	(0.5)	(1.7)	(1.6)
Parent Company Loss Benefit	(2.5)	(1.4)	—
State and Local Income Taxes, Net	6.3	4.8	4.0
Tax Reform Adjustments	—	—	2.8
Tax Reform Excess ADIT Reversal	(24.5)	(15.5)	—
Other	(2.3)	(0.7)	1.9
Income Tax Expense	$ 7.5	$ 5.0	$ 50.1
Effective Income Tax Rate	5.2 %	5.7 %	41.0 %

SWEPCo

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 162.2	$ 152.2	$ 137.5
Less: Equity Earnings – Dolet Hills	(3.0)	(2.7)	—
Income Tax Expense (Benefit)	(4.7)	20.4	48.1
Pretax Income	$ 154.5	$ 169.9	$ 185.6
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 32.4	$ 35.7	$ 65.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.9	3.4	1.9
Depletion	(3.6)	(3.2)	(5.7)
State and Local Income Taxes, Net	(1.3)	3.2	(2.3)
AFUDC	(1.4)	(1.3)	(0.9)
Tax Adjustments	—	—	(9.9)
Tax Reform Adjustments	—	—	(0.4)
Tax Reform Excess ADIT Reversal	(29.9)	(16.0)	—
Other	(2.8)	(1.4)	0.4
Income Tax Expense (Benefit)	$ (4.7)	$ 20.4	$ 48.1
Effective Income Tax Rate	(3.0)%	12.0 %	25.9 %

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,**		
		2019		**2018**
		(in millions)		
Deferred Tax Assets	$	3,246.1	$	2,750.8
Deferred Tax Liabilities		(10,834.3)		(9,837.3)
Net Deferred Tax Liabilities	$	(7,588.2)	$	(7,086.5)
Property Related Temporary Differences	$	(6,602.9)	$	(6,224.8)
Amounts Due to Customers for Future Income Taxes		1,173.5		1,329.7
Deferred State Income Taxes		(1,112.4)		(1,072.5)
Securitized Assets		(178.7)		(186.6)
Regulatory Assets		(371.1)		(454.1)
Accrued Nuclear Decommissioning		(557.4)		(453.7)
Net Operating Loss Carryforward		77.6		78.3
Tax Credit Carryforward		247.2		113.7
Operating Lease Liability		182.6		—
Investment in Partnership		(446.6)		(300.5)
All Other, Net		—		84.0
Net Deferred Tax Liabilities	$	(7,588.2)	$	(7,086.5)

AEP Texas		**December 31,**		
		2019		**2018**
		(in millions)		
Deferred Tax Assets	$	220.0	$	208.1
Deferred Tax Liabilities		(1,185.4)		(1,121.2)
Net Deferred Tax Liabilities	$	(965.4)	$	(913.1)
Property Related Temporary Differences	$	(973.5)	$	(836.3)
Amounts Due to Customers for Future Income Taxes		126.7		141.2
Deferred State Income Taxes		(27.5)		(27.7)
Regulatory Assets		(51.2)		(53.9)
Securitized Transition Assets		(124.3)		(134.7)
Deferred Revenues		19.9		4.6
Operating Lease Liability		17.2		—
All Other, Net		47.3		(6.3)
Net Deferred Tax Liabilities	$	(965.4)	$	(913.1)

AEPTCo

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 162.9	$ 142.9
Deferred Tax Liabilities	(980.7)	(847.3)
Net Deferred Tax Liabilities	$ (817.8)	$ (704.4)
Property Related Temporary Differences	$ (847.1)	$ (755.0)
Amounts Due to Customers for Future Income Taxes	119.9	121.3
Deferred State Income Taxes	(86.1)	(71.6)
Net Operating Loss Carryforward	12.3	13.4
All Other, Net	(16.8)	(12.5)
Net Deferred Tax Liabilities	$ (817.8)	$ (704.4)

APCo

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 486.2	$ 475.2
Deferred Tax Liabilities	(2,167.0)	(2,101.0)
Net Deferred Tax Liabilities	$ (1,680.8)	$ (1,625.8)
Property Related Temporary Differences	$ (1,420.0)	$ (1,393.6)
Amounts Due to Customers for Future Income Taxes	222.8	268.0
Deferred State Income Taxes	(320.9)	(324.1)
Regulatory Assets	(71.0)	(73.8)
Securitized Assets	(49.3)	(54.3)
Operating Lease Liability	16.5	—
All Other, Net	(58.9)	(48.0)
Net Deferred Tax Liabilities	$ (1,680.8)	$ (1,625.8)

I&M

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 970.5	$ 771.6
Deferred Tax Liabilities	(1,950.2)	(1,719.6)
Net Deferred Tax Liabilities	$ (979.7)	$ (948.0)
Property Related Temporary Differences	$ (430.7)	$ (445.0)
Amounts Due to Customers for Future Income Taxes	169.6	186.2
Deferred State Income Taxes	(194.4)	(183.9)
Accrued Nuclear Decommissioning	(557.4)	(453.7)
Regulatory Assets	(26.9)	(31.9)
Net Operating Loss Carryforward	—	0.2
Operating Lease Liability	61.9	—
All Other, Net	(1.8)	(19.9)
Net Deferred Tax Liabilities	$ (979.7)	$ (948.0)

OPCo

	December 31, 2019	December 31, 2018
	(in millions)	
Deferred Tax Assets	$ 202.3	$ 209.0
Deferred Tax Liabilities	(1,051.6)	(972.3)
Net Deferred Tax Liabilities	$ (849.3)	$ (763.3)
Property Related Temporary Differences	$ (890.8)	$ (826.9)
Amounts Due to Customers for Future Income Taxes	130.2	137.0
Deferred State Income Taxes	(35.5)	(32.9)
Regulatory Assets	(48.0)	(55.0)
Operating Lease Liability	18.3	—
All Other, Net	(23.5)	14.5
Net Deferred Tax Liabilities	$ (849.3)	$ (763.3)

PSO

	December 31, 2019	December 31, 2018
	(in millions)	
Deferred Tax Assets	$ 257.4	$ 229.6
Deferred Tax Liabilities	(885.7)	(837.4)
Net Deferred Tax Liabilities	$ (628.3)	$ (607.8)
Property Related Temporary Differences	$ (627.6)	$ (609.4)
Amounts Due to Customers for Future Income Taxes	127.2	138.9
Deferred State Income Taxes	(100.4)	(135.6)
Regulatory Assets	(44.6)	(32.3)
Net Operating Loss Carryforward	10.2	16.4
All Other, Net	6.9	14.2
Net Deferred Tax Liabilities	$ (628.3)	$ (607.8)

SWEPCo

	December 31, 2019	December 31, 2018
	(in millions)	
Deferred Tax Assets	$ 359.6	$ 317.4
Deferred Tax Liabilities	(1,300.5)	(1,220.2)
Net Deferred Tax Liabilities	$ (940.9)	$ (902.8)
Property Related Temporary Differences	$ (947.6)	$ (913.3)
Amounts Due to Customers for Future Income Taxes	169.8	183.4
Deferred State Income Taxes	(200.3)	(193.6)
Regulatory Assets	(30.2)	(30.8)
Net Operating Loss Carryforward	38.2	36.2
All Other, Net	29.2	15.3
Net Deferred Tax Liabilities	$ (940.9)	$ (902.8)

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 ("Parent Company Loss Benefit") 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.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns and as such the IRS may examine only the amended items on the 2014 and 2015 federal returns.

Net Income Tax Operating Loss Carryforward

As of December 31, 2019, AEP has no federal net income tax operating loss carryforward. 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 (in millions)	Years of Expiration
AEP	Arkansas	$ 102.5	2020 - 2024
AEP	Kentucky	144.9	2030 - 2037
AEP	Louisiana	541.0	2025 - 2039
AEP	Oklahoma	544.1	2034 - 2037
AEP	Tennessee	29.0	2028 - 2034
AEP	Virginia	22.6	2030 - 2037
AEP	West Virginia	16.1	2029 - 2037
AEP	Ohio Municipal	414.1	2020 - 2024
AEPTCo	Oklahoma	269.4	2034 - 2037
AEPTCo	Ohio Municipal	37.3	2020 - 2023
I&M	West Virginia	2.0	2031 - 2037
PSO	Oklahoma	240.5	2034 - 2037
SWEPCo	Arkansas	101.7	2021 - 2024
SWEPCo	Louisiana	528.1	2032 - 2037

As of December 31, 2019, AEP has recorded a valuation allowance of $6 million, 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 and 2011 resulted in unused federal and state income tax credits. As of December 31, 2019, 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 2031 through 2039.

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	$ 247.2	$ 239.6	$ 36.7	$ —
AEP Texas	1.4	1.3	—	—
AEPTCo	0.2	0.1	—	—
APCo	4.9	2.3	—	—
I&M	13.9	13.7	—	—
OPCo	5.1	1.7	—	—
PSO	1.1	1.1	36.7	—
SWEPCo	1.9	1.8	—	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

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 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.

Valuation allowance activity for the years ended December 31, 2019, 2018 and 2017 was immaterial.

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, 2019	$ 14.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)
Increase – Tax Positions Taken During a Prior Period	8.8	1.5	—	—	—	1.6	—	0.8
Decrease – Tax Positions Taken During a Prior Period	(2.1)	(0.7)	—	—	(0.7)	—	—	—
Increase – Tax Positions Taken During the Current Year	2.8	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2019	$ 24.1	$ —	$ —	$ —	$ 2.5	$ 8.5	$ —	$ —

	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)

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	2019	2018	2017
		(in millions)	
AEP	$ 20.3	$ 11.6	$ 10.5
AEP Texas	—	(0.7)	(0.5)
AEPTCo	—	—	—
APCo	—	—	—
I&M	2.0	2.6	2.1
OPCo	6.7	5.4	4.5
PSO	—	—	—
SWEPCo	—	(0.6)	(0.5)

Federal Tax Reform and Legislation

In December 2017, Tax Reform legislation was signed into law. Tax Reform included significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%.

The IRS has issued 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 December 31, 2017 and AEP's competitive businesses will be eligible for 100% expensing.

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.

State Tax Legislation

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.

13. LEASES

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

The Registrants lease property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. As of the adoption date of ASU 2016-02, management elected not to separate non-lease components from associated lease components in accordance with the accounting guidance for "Leases." Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain the Registrant will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, the Registrants measure their lease obligation using their estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Effective in 2019, interest on finance lease liabilities is generally charged to Interest Expense. Finance lease interest for periods prior to 2019 were charged to Other Operation and Maintenance expense. Lease costs associated with capital projects are included in Property, Plant and Equipment on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance 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, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 286.0	$ 16.5	$ 2.5	$ 19.5	$ 93.1	$ 18.0	$ 6.8	$ 8.0
Finance Lease Cost:								
Amortization of Right-of-Use Assets	70.8	5.1	0.1	6.7	5.7	3.5	3.1	11.0
Interest on Lease Liabilities	16.4	1.4	—	2.9	2.9	0.7	0.6	2.9
Total Lease Rental Costs (a)	$ 373.2	$ 23.0	$ 2.6	$ 29.1	$ 101.7	$ 22.2	$ 10.5	$ 21.9

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 245.0	$ 13.6	$ 2.7	$ 18.2	$ 89.2	$ 10.7	$ 5.7	$ 6.5
Finance Lease Cost:								
Amortization of Right-of-Use Assets	62.4	4.8	0.1	7.0	6.6	3.9	3.2	11.2
Interest on Lease Liabilities	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)				
Operating Lease Cost	$ 231.3	$ 10.5	$ 1.7	$ 17.5	$ 88.4	$ 8.2	$ 4.4	$ 5.3
Finance Lease Cost:								
Amortization of Right-of-Use Assets	66.3	4.0	—	6.9	11.1	4.1	4.0	11.2
Interest on Lease Liabilities	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

(a) Excludes variable and short-term lease costs, which were immaterial for the twelve months ended December 31, 2019.

Supplemental information related to leases are shown in the tables below:

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	5.23	6.93	2.25	6.28	3.91	7.94	7.07	6.64
Finance Leases	5.85	6.69	0.25	6.12	6.55	6.49	6.23	5.16
Weighted-Average Discount Rate:								
Operating Leases	3.60%	3.77%	3.14%	3.64%	3.45%	3.76%	3.64%	3.76%
Finance Leases	5.98%	4.62%	9.33%	8.08%	8.47%	4.54%	4.62%	5.01%

Year Ended December 31,2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 284.7	$ 15.3	$ 2.4	$ 19.0	$ 94.3	$ 18.0	$ 6.7	$ 7.9
Operating Cash Flows Used for Finance Leases	16.4	1.4	—	2.9	3.1	0.7	0.6	3.0
Financing Cash Flows Used for Finance Leases	70.7	5.1	—	6.7	5.7	3.5	3.1	11.0
Non-cash Acquisitions Under Operating Leases	$ 125.0	$ 13.8	$ 0.6	$ 10.2	$ 18.7	$ 35.4	$ 8.2	$ 11.4

The following tables show property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 131.6	$ —	$ —	$ 39.9	$ 28.8	$ —	$ 0.6	$ 34.1
Other Property, Plant and Equipment	323.0	45.9	0.2	18.9	39.3	27.3	21.6	51.6
Total Property, Plant and Equipment	454.6	45.9	0.2	58.8	68.1	27.3	22.2	85.7
Accumulated Amortization	151.5	11.8	0.2	17.0	23.0	7.2	7.1	28.4
Net Property, Plant and Equipment Under Finance Leases	$ 303.1	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.3
Obligations Under Finance Leases:								
Noncurrent Liability	$ 249.2	$ 28.2	$ —	$ 35.0	$ 38.8	$ 16.2	$ 11.9	$ 47.1
Liability Due Within One Year	57.6	5.9	—	6.8	6.3	3.9	3.2	10.5
Total Obligations Under Finance Leases	$ 306.8	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.6

December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance 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 Finance Leases	$ 278.8	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 54.2
Obligations Under Finance 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 Finance Leases	$ 289.0	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 957.4	$ 81.8	$ 3.8	$ 78.5	$ 294.9	$ 88.0	$ 36.8	$ 40.5
Obligations Under Operating Leases:								
Noncurrent Liability	$ 734.6	$ 71.1	$ 1.9	$ 64.0	$ 211.6	$ 76.0	$ 31.0	$ 34.7
Liability Due Within One Year	234.1	12.0	2.1	15.2	87.3	12.5	5.8	6.5
Total Obligations Under Operating Leases	$ 968.7	$ 83.1	$ 4.0	$ 79.2	$ 298.9	$ 88.5	$ 36.8	$ 41.2

Future minimum lease payments consisted of the following as of December 31, 2019:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2020	$ 72.7	$ 7.3	$ —	$ 9.6	$ 9.4	$ 4.7	$ 3.8	$ 12.9
2021	64.9	6.7	—	8.9	8.7	4.3	3.2	11.9
2022	56.4	6.0	—	8.2	8.0	3.4	2.6	10.6
2023	49.6	5.4	—	7.7	7.5	2.8	2.3	9.8
2024	57.4	4.6	—	7.1	10.8	2.4	1.8	14.2
Later Years	64.4	9.8	—	9.8	16.4	5.7	3.8	6.8
Total Future Minimum Lease Payments	365.4	39.8	—	51.3	60.8	23.3	17.5	66.2
Less: Imputed Interest	58.6	5.7	—	9.5	15.7	3.2	2.4	8.6
Estimated Present Value of Future Minimum Lease Payments	$ 306.8	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.6

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2020	$ 269.9	$ 16.0	$ 2.2	$ 18.3	$ 97.0	$ 16.2	$ 7.3	$ 8.6
2021	253.6	15.3	1.2	15.7	92.9	14.2	6.4	8.2
2022	245.6	14.2	0.6	14.7	92.8	13.5	6.0	7.6
2023	74.8	13.0	0.1	11.9	10.1	12.3	5.6	6.4
2024	62.0	11.4	—	9.0	8.6	10.7	4.8	5.0
Later Years	169.7	26.0	—	20.0	21.0	36.5	12.0	11.8
Total Future Minimum Lease Payments	1,075.6	95.9	4.1	89.6	322.4	103.4	42.1	47.6
Less: Imputed Interest	106.9	12.8	0.1	10.4	23.5	14.9	5.3	6.4
Estimated Present Value of Future Minimum Lease Payments	$ 968.7	$ 83.1	$ 4.0	$ 79.2	$ 298.9	$ 88.5	$ 36.8	$ 41.2

Future minimum lease payments consisted of the following as of December 31, 2018:

Finance 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: Imputed Interest	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

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, 2019, 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	$ 47.3
AEP Texas	11.3
APCo	6.6
I&M	4.1
OPCo	7.3
PSO	4.2
SWEPCo	4.8

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. In the first quarter of 2019, in accordance with ASU 2016-02, the $37 million unamortized gain ($15 million related to I&M) associated with the sale-and-leaseback of the Plant was recognized as an adjustment to equity. The adjustment to equity was then reclassified to regulatory liabilities in accordance with accounting guidance for "Regulated Operations" as AEGCo and I&M will continue to provide the benefit of the unamortized gain to customers in future periods.

The Owner Trustee owns the Plant and leases equal portions 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 and at the end of the lease term, AEGCo and I&M have the option to renew the lease at a rate that approximates fair value. The option to renew was not included in the measurement of the lease obligation as of December 31, 2019 as the execution of the option was not reasonably certain. 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, 2019 were as follows:

Future Minimum Lease Payments	**AEP (a)**	**I&M**
	(in millions)	
2020	$ 147.8	$ 73.9
2021	147.8	73.9
2022	147.5	73.7
Total Future Minimum Lease Payments	$ 443.1	$ 221.5

(a) AEP's future minimum lease payments include equal shares from AEGCo and I&M.

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 respective lessors, ensuring future payments under such leases with maturities up to 2027. As of December 31, 2019, the maximum potential amount of future payments required under the guaranteed leases was $55 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor's rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of December 31, 2019, AEP's boat and barge lease guarantee liability was $5 million, of which $2 million was recorded in Other Current Liabilities and $3 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

In February 2020, the nonaffiliated party filed Chapter 11 bankruptcy. The party entered into a restructuring support agreement and has announced it expects to continue their operations as normal. Management has determined that it is reasonably possible that enforcement of AEP's liability for future payments under these leases will be exercised within the next twelve months. In such an event, if AEP is unable to sell or incorporate any of the acquired assets into its fleet operations, it could reduce future net income and cash flows and impact financial condition.

Lessor Activity

The Registrants' lessor activity was immaterial as of and for the twelve months ended December 31, 2019.

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, 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
Issued	923,595	—
Balance, December 31, 2019	514,373,631	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, 2019	Interest Rate Ranges as of December 31, 2019	Interest Rate Ranges as of December 31, 2018	Outstanding as of December 31, 2019	Outstanding as of December 31, 2018
AEP					(in millions)	
Senior Unsecured Notes	2019-2050	4.29%	2.15%-8.13%	2.15%-8.13%	$ 21,180.7	$ 18,903.3
Pollution Control Bonds (a)	2019-2038 (b)	2.75%	1.35%-5.38%	1.60%-6.30%	1,998.8	1,643.8
Notes Payable – Nonaffiliated (c)	2019-2032	3.27%	2.42%-6.37%	3.20%-6.37%	234.3	204.7
Securitization Bonds	2019-2029 (d)	3.23%	1.98%-5.31%	1.98%-5.31%	1,025.1	1,111.4
Spent Nuclear Fuel Obligation (e)					279.8	273.6
Junior Subordinated Notes (f)	2022	3.40%	3.40%		787.8	—
Other Long-term Debt	2019-2059	3.03%	1.15%-13.718%	1.15%-13.718%	1,219.0	1,209.9
Total Long-term Debt Outstanding					$ 26,725.5	$ 23,346.7
AEP Texas						
Senior Unsecured Notes	2019-2050	4.01%	2.40%-6.76%	2.40%-6.76%	$ 3,090.9	$ 2,398.4
Pollution Control Bonds	2020-2030	3.63%	1.75%-4.55%	1.75%-6.30%	490.3	490.9
Securitization Bonds	2020-2029 (d)	3.25%	1.98%-5.31%	1.98%-5.31%	776.8	791.2
Other Long-term Debt	2019-2059	3.06%	3.05%-4.50%	3.94%-4.50%	200.4	200.8
Total Long-term Debt Outstanding					$ 4,558.4	$ 3,881.3
AEPTCo						
Senior Unsecured Notes	2019-2049	3.86%	3.10%-5.52%	2.68%-5.52%	$ 3,427.3	$ 2,823.0
Total Long-term Debt Outstanding					$ 3,427.3	$ 2,823.0
APCo						
Senior Unsecured Notes	2021-2049	5.12%	3.30%-7.00%	3.30%-7.00%	$ 3,442.7	$ 3,047.3
Pollution Control Bonds (a)	2019-2038 (b)	2.64%	1.67%-5.38%	1.70%-5.38%	546.1	616.0
Securitization Bonds	2023-2028 (d)	3.17%	2.008%-3.772%	2.008%-3.772%	248.3	272.3
Other Long-term Debt	2019-2026	3.14%	2.97%-13.718%	3.74%-13.718%	126.7	127.0
Total Long-term Debt Outstanding					$ 4,363.8	$ 4,062.6
I&M						
Senior Unsecured Notes	2023-2048	4.38%	3.20%-6.05%	3.20%-6.05%	$ 2,150.7	$ 2,149.0
Pollution Control Bonds (a)	2019-2025 (b)	2.55%	1.79%-3.05%	1.81%-3.05%	240.0	264.5
Notes Payable – Nonaffiliated (c)	2019-2024	2.49%	2.42%-2.80%	3.20%-3.38%	168.7	135.8
Spent Nuclear Fuel Obligation (e)					279.8	273.6
Other Long-term Debt	2021-2025	3.09%	2.93%-6.00%	3.66%-6.00%	211.0	212.5
Total Long-term Debt Outstanding					$ 3,050.2	$ 3,035.4
OPCo						
Senior Unsecured Notes	2021-2049	5.20%	4.00%-6.60%	4.15%-6.60%	$ 2,081.0	$ 1,635.5
Pollution Control Bonds	2038			5.80%	—	32.3
Securitization Bonds	2019 (d)			2.049%	—	47.8
Other Long-term Debt	2028	1.15%	1.15%	1.15%	1.0	1.0
Total Long-term Debt Outstanding					$ 2,082.0	$ 1,716.6
PSO						
Senior Unsecured Notes	2019-2049	4.55%	3.05%-6.625%	3.05%-6.625%	$ 1,245.6	$ 1,144.9
Pollution Control Bonds	2020	4.45%	4.45%	4.45%	12.7	12.6
Other Long-term Debt	2019-2027	3.19%	3.00%-3.20%	3.00%-3.72%	127.9	129.5
Total Long-term Debt Outstanding					$ 1,386.2	$ 1,287.0
SWEPCo						
Senior Unsecured Notes	2022-2048	4.04%	2.75%-6.20%	2.75%-6.20%	$ 2,428.9	$ 2,427.0
Pollution Control Bonds	2019			1.60%	—	53.5
Notes Payable – Nonaffiliated (c)	2024-2032	5.26%	4.58%-6.37%	4.58%-6.37%	65.6	68.9
Other Long-term Debt	2020-2035	3.55%	3.08%-4.68%	3.75%-4.68%	161.1	164.0
Total Long-term Debt Outstanding					$ 2,655.6	$ 2,713.4

(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.
(f) See "Equity Units" section below for additional information.

As of December 31, 2019, outstanding long-term debt was payable as follows:

	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
2020	$ 1,598.7		$ 392.1	$ —	$ 215.6	$ 139.7	$ 0.1	$ 13.2	$ 121.2
2021	2,022.7		88.7	50.0	393.0	291.5	500.1	250.5	6.2
2022	3,014.6	(a)	716.0	104.0	355.4	26.8	0.1	125.5	281.2
2023	739.9		218.5	60.0	26.6	259.2	0.1	0.6	6.2
2024	706.5		96.0	95.0	113.5	4.2	0.1	0.6	31.2
After 2024	18,863.1		3,081.4	3,156.0	3,296.9	2,355.3	1,600.5	1,001.4	2,231.7
Principal Amount	26,945.5		4,592.7	3,465.0	4,401.0	3,076.7	2,101.0	1,391.8	2,677.7
Unamortized Discount, Net and Debt Issuance Costs	(220.0)		(34.3)	(37.7)	(37.2)	(26.5)	(19.0)	(5.6)	(22.1)
Total Long-term Debt Outstanding	$ 26,725.5		$ 4,558.4	$ 3,427.3	$ 4,363.8	$ 3,050.2	$ 2,082.0	$ 1,386.2	$ 2,655.6

(a) Amount includes $805 million of Junior Subordinated Notes. See "Equity Units" section below for additional information.

As of December 31, 2019, trustees held, on behalf of AEP, $35 million of their reacquired Pollution Control Bonds. Of this total, $35 million related to OPCo. In January 2020, those Pollution Control Bonds were redeemed.

Long-term Debt Subsequent Events

In January and February 2020, AEP Texas retired $111 million and $3 million, respectively, of Securitization Bonds.

In January and February 2020, I&M retired $8 million and $5 million, respectively, of Notes Payable related to DCC Fuel.

In January 2020, Transource Energy issued $4 million of variable rate Other Long-term Debt due in 2023.

In February 2020, APCo retired $12 million of Securitization Bonds.

Equity Units (Applies to AEP)

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. The proceeds were used to support AEP's overall capital expenditure plans including the acquisition of Sempra Renewables LLC.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes (notes) due in 2024 and a forward equity purchase contract which settles after three years in 2022. The notes are expected to be remarketed in 2022, at which time the interest rate will reset at the then current market rate. Investors may choose to remarket their notes to receive the remarketing proceeds and use those funds to settle the forward equity purchase contract, or accept the remarketed debt and use other funds for the equity purchase. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the principal. The Equity Units carry an annual distribution rate of 6.125%, which is comprised of a quarterly coupon rate of interest of 3.40% and a quarterly forward equity purchase contract payment of 2.725%.

Each forward equity purchase contract obligates the holder to purchase, and AEP to sell, for $50 a number of shares in common stock in accordance with the conversion ratios set forth below (subject to an anti-dilution adjustment):

- If the AEP common stock market price is equal to or greater than $99.58: 0.5021 shares per contract.
- If the AEP common stock market price is less than $99.58 but greater than $82.98: a number of shares per contract equal to $50 divided by the applicable market price. The holder receives a variable number of shares at $50.
- If the AEP common stock market price is less than or equal to $82.98: 0.6026 shares per contract.

A holder's ownership interest in the notes is pledged to AEP to secure the holder's obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder's obligation under the forward equity purchase contract must be secured by a U.S. Treasury security which must be equal to the aggregate principal amount of the notes.

At the time of issuance, the $805 million of notes were recorded within Long-term Debt on the balance sheets. The present value of the purchase contract payments of $62 million were recorded in Deferred Credits and Other Noncurrent Liabilities with a current portion in Other Current Liabilities at the time of issuance, representing the obligation to make forward equity contract payments, with an offsetting reduction to Paid-in Capital. The difference between the face value and present value of the purchase contract payments will be accreted to Interest Expense on the statements of income over the three year period ending in 2022. The liability recorded for the contract payments is considered non-cash and excluded from the statements of cash flows. Until settlement of the forward equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method. The maximum amount of shares AEP will be required to issue to settle the purchase contract is 9,701,860 shares (subject to an anti-dilution adjustment).

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 1.6% of consolidated tangible net assets as of December 31, 2019. 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. The Federal Power Act also 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, 2019, 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 $13.2 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, 2019, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 1,741.4 (a)	$ 385.0	$ —	$ 26.3	$ 524.5	$ —	$ 153.0	$ 534.5

(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, 2019, AEP had $7.2 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.3 billion, $1.3 billion and $1.2 billion of dividends to common shareholders for the years ended December 31, 2019, 2018 and 2017, 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, 2019, AEP had a $4 billion revolving credit facility to support its commercial paper program. The commercial paper program for the year ended 2019, had a weighted-average interest rate of 2.51% and a maximum amount outstanding of $2.2 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2019		2018	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in millions)		**(in millions)**	
AEP	Securitized Debt for Receivables (b)	$ 710.0	2.42%	$ 750.0	2.16%
AEP	Commercial Paper	2,110.0	2.10%	1,160.0	2.96%
SWEPCo	Notes Payable	18.3	3.29%	—	—%
	Total Short-term Debt	$ 2,838.3		$ 1,910.0	

(a) Weighted-average 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 its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2019 and 2018 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, 2019:

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, 2019	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 390.7	$ 213.1	$ 239.3	$ 194.4	$ 199.7	$ 500.0	
AEPTCo	374.9	244.4	152.0	52.8	(119.0)	795.0	(a)
APCo	270.0	232.2	115.9	51.9	(214.6)	500.0	
I&M	158.8	66.0	71.5	16.2	(101.2)	500.0	
OPCo	291.2	178.6	129.2	50.1	(131.0)	500.0	
PSO	140.5	215.6	63.9	98.3	38.8	300.0	
SWEPCo	105.1	81.4	53.3	13.6	(59.9)	350.0	

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	

(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, 2019 and 2018 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, 2019:

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, 2019
		(in millions)	
AEP Texas	$ 8.0	$ 7.7	$ 7.5
SWEPCo	2.1	2.0	2.1

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

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to and borrowings from AEP as of December 31, 2019 and 2018 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2019:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2019	Loans to AEP as of December 31, 2019	Authorized Short-term Borrowing Limit
			(in millions)			
$ 1.3	$ 153.5	$ 1.3	$ 68.0	$ 1.3	$ 68.7	$ 75.0 (a)

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)

(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,		
	2019	2018	2017
Maximum Interest Rate	3.43%	2.97%	1.85%
Minimum Interest Rate	1.77%	1.81%	0.92%

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	2019	2018	2017	2019	2018	2017
AEP Texas	2.63%	2.26%	1.29%	2.03%	2.29%	1.26%
AEPTCo	2.64%	2.27%	1.36%	2.41%	2.10%	1.27%
APCo	2.45%	2.26%	1.28%	2.66%	2.21%	1.29%
I&M	2.34%	2.16%	1.27%	2.60%	2.08%	1.29%
OPCo	2.67%	2.18%	1.37%	2.68%	2.47%	0.98%
PSO	2.85%	2.27%	1.32%	2.27%	1.98%	—%
SWEPCo	2.72%	2.31%	1.28%	2.22%	2.00%	0.98%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool are summarized in the following table:

Year Ended December 31,	Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
2019	AEP Texas	3.02%	1.91%	2.56%
2019	SWEPCo	3.02%	1.91%	2.55%
2018	AEP Texas	2.97%	1.83%	2.36%
2018	SWEPCo	2.97%	1.83%	2.36%
2017	AEP Texas	1.85%	—%	1.32%
2017	SWEPCo	1.85%	—%	1.32%

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Year Ended December 31,	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
2019	3.02%	1.91%	3.02%	1.91%	2.55%	2.51%
2018	2.97%	1.76%	2.97%	1.76%	2.36%	2.36%
2017	1.85%	0.92%	1.85%	0.92%	1.33%	1.36%

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, 2019, 2018 and 2017.

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 that provides a commitment of $750 million from bank conduits to purchase receivables and expires in July 2021. 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.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31, 2019	2018	2017
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	2.42%	2.16%	1.22%
Net Uncollectible Accounts Receivable Written Off	$ 26.6	$ 27.6	$ 23.4

	December 31, 2019	2018
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 841.8	$ 972.5
Short-term – Securitized Debt of Receivables	710.0	750.0
Delinquent Securitized Accounts Receivable	39.6	50.3
Bad Debt Reserves Related to Securitization	32.1	27.5
Unbilled Receivables Related to Securitization	266.8	281.4

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, 2019	2018
	(in millions)	
APCo	$ 120.9	$ 133.3
I&M	141.8	152.9
OPCo	330.3	395.2
PSO	101.1	109.7
SWEPCo	125.2	150.3

The fees paid to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
APCo	$ 7.4	$ 7.0	$ 5.6
I&M	11.1	9.2	6.7
OPCo	27.1	26.3	21.7
PSO	7.8	7.9	7.0
SWEPCo	10.2	8.9	7.2

The proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
APCo	$ 1,310.3	$ 1,421.0	$ 1,372.8
I&M	1,824.2	1,843.0	1,612.9
OPCo	2,293.6	2,674.5	2,339.0
PSO	1,442.5	1,484.6	1,337.0
SWEPCo	1,618.5	1,736.1	1,563.4

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 AEP common shares to be available for grant to eligible employees and directors. As of December 31, 2019, 7,667,992 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 units, cash-based awards and other stock-based awards. Shares issued pursuant to a stock option or a stock appreciation right reduce the shares remaining available for grants under the 2015 LTIP by 0.286 of a share. Shares issued for any other awards that settles in AEP stock reduce the shares remaining available for grants under the 2015 LTIP by one share. Cash settled awards do not reduce the number of shares remaining available under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Shares

Performance units granted prior to 2017 were settled in cash rather than AEP common stock and did not reduce the number of shares remaining available under the 2015 LTIP. Those performance units had 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 shares granted in and after 2017 are settled in AEP common stock and will reduce the aggregate share authorization. In all cases the number of performance shares 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 shares 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 a minimum stock ownership requirement. If those employees have not met their stock ownership requirement, a portion or all of their performance shares 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 a share 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 shares and AEP career shares accrue as additional shares. Management records compensation cost for performance shares over an approximately three-year vesting period. The liability for the pre-2017 performance units was recorded in Employee Benefits and Pension Obligations on the balance sheets and was adjusted for changes in value. Performance shares are recorded as mezzanine equity on the balance sheets and compensation cost is calculated at fair value using two equally weighted metrics. The first metric is a total shareholder return measure, which is valued based on a third-party Monte Carlo valuation. The value related to this metric does not change over the three-year vesting period. The second metric is 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 shares and reinvested dividends on outstanding performance shares and AEP career shares as follows:

Performance Shares	Years Ended December 31, 2019	2018	2017
Awarded Shares (in thousands)	535.0	581.4	590.7
Weighted Average Share Fair Value at Grant Date	$ 83.21	$ 67.21	$ 69.78
Vesting Period (in years)	3	3	3

Performance Shares and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2019	2018	2017
Awarded Shares (in thousands) (a)	66.4	80.2	74.6
Weighted Average Fair Value at Grant Date	$ 88.73	$ 70.58	$ 72.35
Vesting Period (in years)	(b)	(b)	(b)

(a) All awarded dividends in 2019 were equity awards and awarded dividends in both 2018 and 2017 were a mix of equity awards and liability awards.

(b) The vesting period for the reinvested dividends on performance shares is equal to the remaining life of the related performance shares. 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 two months 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 shares earned for the three-year periods were as follows:

Performance Shares	Years Ended December 31, 2019	2018	2017
Certified Performance Score	132.7%	136.7%	164.8%
Performance Shares Earned	792,897	820,780	956,055
Performance Shares Mandatorily Deferred as AEP Career Shares	10,063	11,248	20,213
Performance Shares Voluntarily Deferred into the Incentive Compensation Deferral Program	49,392	56,826	47,177
Performance Shares to be Settled (a)	733,442	752,706	888,665

(a) Performance shares settled for the three-year period ended December 31, 2019 settled in AEP common stock. Performance units settled for the three-year period ended December 31, 2018 and 2017 settled in cash.

The settlements were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2019	2018	2017
		(in millions)	
Cash Settlements for Performance Units	$ 58.3	$ 66.9	$ 64.9
AEP Common Stock Settlements for Career Share Distributions	6.6	5.1	0.4

A summary of the status of AEP's nonvested Performance Shares as of December 31, 2019 and changes during the year ended December 31, 2019 were as follows:

Nonvested Performance Shares	Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2019	1,171.3	$ 66.01
Granted	582.5	80.30
Vested (a)	(597.5)	65.42
Forfeited	(42.9)	70.32
Nonvested as of December 31, 2019	1,113.4	73.64

(a) The vested Performance Shares will be converted to 733 thousand shares based on the closing share price on the day before settlement.

Monte Carlo Valuation

AEP engages a third-party for a Monte Carlo valuation to calculate half of the fair value for the performance shares 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 were as follows:

Monte Carlo Valuation	Years Ended December 31, 2019	2018	2017
Valuation Period (in years) (a)	2.87	2.87	2.86
Expected Volatility Minimum	14.83%	14.77%	15.65%
Expected Volatility Maximum	25.57%	26.72%	27.19%
Expected Volatility Average	17.39%	17.90%	19.07%
Dividend Rate (b)	—%	—%	—%
Risk Free Rate	2.49%	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 the RSUs granted prior to 2017 to AEP's executive officers which 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 that settle 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 that 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 was 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, as follows:

Restricted Stock Units	Years Ended December 31, 2019	2018	2017
Awarded Units (in thousands)	304.8	260.0	255.8
Weighted Average Grant Date Fair Value	$ 81.57	$ 67.96	$ 65.26

The total fair value and total intrinsic value of restricted stock units vested were as follows:

Restricted Stock Units	Years Ended December 31, 2019	2018	2017
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 16.3	$ 16.6	$ 16.1
Intrinsic Value of Restricted Stock Units Vested (a)	21.6	19.2	20.0

(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, 2019 and changes during the year ended December 31, 2019 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2019	489.1	$ 66.01
Granted	304.8	81.57
Vested	(253.7)	64.44
Forfeited	(23.3)	70.27
Nonvested as of December 31, 2019	516.9	75.55

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2019 was $49 million and the weighted average remaining contractual life was 1.79 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 on their 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 subsequent AEP stock units as 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, 2019, 2018 and 2017, cash settlements for stock unit distributions were immaterial.

The Board of Directors awarded stock units, including units awarded for dividends, as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2019	2018	2017
Awarded Units (in thousands)	10.0	11.4	14.8
Weighted Average Grant Date Fair Value	$ 89.13	$ 70.41	$ 70.79

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 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2019	2018	2017
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 57.9	$ 53.2	$ 79.5
Actual Tax Benefit (b)	8.4	7.7	18.9
Total Compensation Cost Capitalized	20.0	19.7	26.4

(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 generally 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, 2019, there was $73 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance shares 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 1.43 years.

Under the 2015 LTIP, 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 (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the PCA. Under the 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.

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 (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 tables below represent revenues from affiliates, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2019							
Direct Sales to East Affiliates	$ —	$ —	$ 128.6	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	—
Auction Sales to OPCo (a)	—	—	11.4	6.7	—	—	—
Direct Sales to AEPEP	157.2	—	—	—	—	—	(0.1)
Transmission Revenues	—	795.5	58.5	0.7	7.7	1.3	3.6
Other Revenues	3.3	11.2	6.8	3.1	19.6	4.8	1.4
Total Affiliated Revenues	$ 160.5	$ 806.7	$ 205.3	$ 10.5	$ 27.3	$ 6.1	$ 4.9

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 Revenues	—	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 Revenues	—	559.6	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

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.

The tables below represent the purchased power expenses incurred for purchases from affiliates. AEP Texas, AEPTCo, APCo, PSO and SWEPCo did not purchase any power from affiliates for the years ended December 31, 2019, 2018 and 2017.

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2019		
Auction Purchases from AEPEP (a)	$ —	$ 64.6
Auction Purchases from AEP Energy (a)	—	69.9
Auction Purchases from AEPSC (a)	—	21.5
Direct Purchases from AEGCo	214.9	—
Total Affiliated Purchases	$ 214.9	$ 156.0

Related Party Purchases	I&M	OPCo
	(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
	(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

(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.

PJM and SPP Transmission Service Charges (Applies to all Registrant Subsidiaries except AEP Texas)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the Transmission Agreement (TA), which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT.

The following table shows the net transmission service charges recorded by APCo, I&M and OPCo:

	Years Ended December 31,		
Company	**2019**	**2018**	**2017**
		(in millions)	
APCo	$ 222.3	$ 128.3	$ 158.2
I&M	143.5	91.4	103.8
OPCo	373.4	210.1	248.6

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the Transmission Coordination Agreement (TCA) in connection with the operation of the transmission assets of PSO and SWEPCo. 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. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.

The following table shows the net transmission service charges recorded by PSO and SWEPCo:

	Years Ended December 31,		
Company	**2019**	**2018**	**2017**
		(in millions)	
PSO	$ 46.9	$ 65.9	$ 56.0
SWEPCo	20.1	10.5	6.6

The charges shown above are recorded in Other Operation expenses on the statements of income.

AEPTCo provides transmission services to affiliates in accordance with the OATT, TA and TCA. AEPTCo recorded affiliated transmission revenues 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, $27 million and $30 million for transmission services in 2019, 2018 and 2017, 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 $157 million, $104 million and $64 million from AEPEP for the years ended December 31, 2019, 2018 and 2017, respectively. These amounts are included in Sales to AEP Affiliates on AEP Texas' statements of income.

Joint License Agreement (Applies to AEPTCo, APCo, I&M, OPCo and PSO)

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, 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. AEPTCo recorded the following costs in Other Operation expense related to these agreements:

	Years Ended December 31,		
Billing Company	**2019**	**2018**	**2017**
		(in millions)	
APCo	$ 0.2	$ —	$ —
I&M	1.5	2.2	1.4
KPCo	0.3	0.2	0.2
OPCo	2.2	2.9	2.4
PSO	0.3	0.3	0.3
WPCo	0.1	—	—

APCo, I&M, KPCo, OPCo, PSO and WPCo 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 and see "Ohio ESP Filings" section of Note 4 for additional information.

Unit Power Agreements (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 $13 million, $12 million and $10 million in 2019, 2018 and 2017, 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 were as follows:

	Years Ended December 31,		
Company	**2019**	**2018**	**2017**
		(in millions)	
I&M	$ 1.3	$ 1.5	$ 1.3
PSO	0.8	0.7	0.5
SWEPCo	4.0	3.4	3.5

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	**2019**	**2018**	**2017**
		(in millions)	
AEGCo	$ 14.9	$ 19.9	$ 15.3
AGR	—	—	0.1
APCo	38.9	35.1	37.2
KPCo	4.8	4.2	5.0
WPCo	4.8	4.2	5.0

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	**2019**	**2018**	**2017**
		(in millions)	
AGR	$ 0.8	$ 1.6	$ 1.2
I&M	2.3	2.4	2.7
KPCo	1.4	1.7	1.8
PSO	1.1	0.5	1.1
SWEPCo	1.1	0.7	0.8

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:

Sales

Company	Years Ended December 31, 2019	2018	2017
		(in millions)	
AEP Texas	$ 0.9	$ 0.3	$ 0.2
APCo	5.5	5.4	3.5
I&M	7.5	8.2	5.0
OPCo	7.0	10.7	2.9
PSO	0.8	1.0	1.5
SWEPCo	0.2	0.8	0.5

Purchases

Company	Years Ended December 31, 2019	2018	2017
		(in millions)	
AEP Texas	$ 0.3	$ 0.1	$ 0.4
AEPTCo	10.2	18.5	9.1
APCo	6.0	0.6	0.9
I&M	0.9	2.0	3.5
OPCo	3.0	2.8	1.6
PSO	0.5	1.3	0.2
SWEPCo	0.7	0.8	0.4

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Sempra Renewables LLC PPAs (Applies to I&M, OPCo and SWEPCo)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation. The operating wind generation portfolio includes seven wind farms. Prior to the acquisition, two wind farms had existing PPAs with I&M, OPCo and SWEPCo. See “Acquisitions” section of Note 7 for additional information.

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.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. Charitable contributions to the AEP Foundation were recorded in Other Operation on the statements of income. The contributions recorded were as follows:

Company	**Year Ended December 31, 2019**
	(in millions)
AEP	$ 50.0
AEP Texas	6.2
AEPTCo	6.5
APCo	8.9
I&M	9.0
OPCo	5.4
PSO	3.4
SWEPCo	5.5

17. VARIABLE INTEREST ENTITIES AND EQUITY METHOD INVESTMENTS

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 holds ownership interests in businesses with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE, and if so, whether or not the VIE should be consolidated into AEP's financial statements. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. If an entity is determined not to be a VIE, or if the entity is determined to be a VIE and AEP is not deemed to be the primary beneficiary, the entity is accounted for under the equity method of accounting.

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, 2019, 2018 and 2017 were $110 million, $152 million and $137 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

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 $155 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. SWEPCo recovers these costs through its fuel clauses. As of December 31, 2019, SWEPCo has recorded $83 million of mine reclamation costs in Asset Retirement Obligations and has collected $78 million through a rider for reclamation costs. The remaining $5 million is recorded in Deferred Charges and Other Noncurrent Assets 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, 2019, 2018 and 2017 were $95 million, $113 million and $136 million, respectively. The leases were recorded as finance 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 finance 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 $541 million and $791 million as of December 31, 2019 and 2018, 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 $389 million and $637 million as of December 31, 2019 and 2018, 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.

Restoration Funding

Restoration Funding was formed for the sole purpose of issuing and servicing securitization bonds related to storm restoration of AEP Texas' distribution system primarily due to damage caused by Hurricane Harvey. See "Texas Storm Cost Securitization" section of Note 4 for additional information. Management has concluded that AEP Texas is the primary beneficiary of Restoration 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 Restoration Funding. The securitized bonds totaled $235 million as of December 31, 2019 and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Restoration Funding has securitized assets of $232 million as of December 31, 2019 which are presented separately on the face of the balance sheets. The securitized restoration assets represent the right to impose and collect Texas storm restoration 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 assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Restoration Funding's securitized assets and remits all related amounts collected from customers to Restoration Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Restoration 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. In July 2019, the securitization bonds matured. 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 \$0 and \$48 million as of December 31, 2019 and 2018, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of \$0 and \$13 million as of December 31, 2019 and 2018, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represented 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. The securitization bonds were payable only from and secured by the securitized assets. The bondholders had no recourse to OPCo or any other AEP entity. OPCo acted as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remitted 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 \$223 million and \$272 million as of December 31, 2019 and 2018, 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 \$235 million and \$259 million as of December 31, 2019 and 2018, 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 six 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, 2019, 2018 and 2017 was $34 million, $34 million and $29 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, 2019, 2018 and 2017, AEP provided capital contributions to Transource Energy of $0, $4 million and $5 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 PTC and cash distributions from the operation of the LLCs generally consistent with the ownership percentages. See the tables 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, 2019 and 2018, AEP recorded \$66 million and \$69 million, respectively, of Redeemable Noncontrolling Interest in Mezzanine Equity on the balance sheets.

Apple Blossom Wind Holdings LLC and Black Oak Getty Wind Holdings LLC

In April 2019, AEP acquired an equity interest in Apple Blossom Wind Holdings LLC (Apple Blossom) and Black Oak Getty Wind Holdings LLC (Black Oak) (collectively the Project Entities) as part of the purchase of Sempra Renewables LLC. Both of the Project Entities have long-term PPAs for 100% of their energy production. The Project Entities are tax equity partnerships with nonaffiliated noncontrolling interests to which a percentage of earnings, tax attributes and cash flows are allocated in accordance with the respective limited liability company agreements. Management has concluded that the Project Entities are VIEs and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact the Project Entities' economic performance. In addition, AEP has not provided material financial or other support to the Project Entities that was not previously contractually required. As the primary beneficiary of the Project Entities, AEP consolidates the Project Entities into its financial statements. See the table below for the classification of Project Entities' assets and liabilities on the balance sheets.

The nonaffiliated interests in the Project Entities is presented in Noncontrolling Interests on the balance sheets. As of December 31, 2019, AEP recorded \$128 million of Noncontrolling Interests related to the Project Entities in Equity on the balance sheets.

The Project Entities' tax equity partnerships represent substantive profit-sharing arrangements. The method for attributing income and loss to the noncontrolling interests is a balance sheet approach referred to as the hypothetical liquidation at book value (HLBV) method. Under the HLBV method, the income and loss attributable to the noncontrolling interests reflect changes in the amounts the members would hypothetically receive at each balance sheet date under the liquidation provisions of the respective limited liability company agreements, assuming the net assets of these entities were liquidated at recorded amounts, after taking into account any capital transactions, such as contributions or distributions, between the entities and the members. For the year ended December 31, 2019, the HLBV method resulted in a loss of \$6 million allocated to Noncontrolling Interests.

Santa Rita East

In July 2019, AEP acquired a 75% interest in Santa Rita East Wind Energy Holdings, LLC and its wholly-owned subsidiary, Santa Rita East Wind Energy, LLC (collectively, Santa Rita East). Santa Rita East is a partnership whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas. Santa Rita East delivers energy and provides renewable energy credits through three long-term PPAs totaling 260 MWs. The remaining 42 MWs of energy are sold at wholesale into ERCOT. Management has concluded that Santa Rita East is a VIE and that AEP is the primary beneficiary based on its power as managing member of the partnership to direct the activities that most significantly impact Santa Rita East's economic performance. As the primary beneficiary of Santa Rita East, AEP consolidates Santa Rita East into its financial statements. See the table below for the classification of Santa Rita East's assets and liabilities on the balance sheets.

AEP recognized \$10 million of PTC attributable to Santa Rita East for the year ended December 31, 2019 which was recorded in Income Tax Expense (Benefit) on the statements of income. The nonaffiliated interest in Santa Rita East is presented in Noncontrolling Interests on the balance sheets. As of December 31, 2019, AEP recorded \$118 million of Noncontrolling Interests related to Santa Rita East in 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, 2019

	Registrant Subsidiaries					
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**AEP Texas Restoration Funding**	**OPCo Ohio Phase-in-Recovery Funding**	**APCo Appalachian Consumer Rate Relief Funding**
	(in millions)					
ASSETS						
Current Assets	$ 80.0	$ 86.5	$ 187.0	$ 9.4	$ —	$ 21.5
Net Property, Plant and Equipment	111.6	156.8	—	—	—	—
Other Noncurrent Assets	93.2	82.5	428.1 (a)	234.4 (b)	—	237.5 (c)
Total Assets	$ 284.8	$ 325.8	$ 615.1	$ 243.8	$ —	$ 259.0
LIABILITIES AND EQUITY						
Current Liabilities	$ 50.6	$ 86.4	$ 280.2	$ 16.3	$ —	$ 28.3
Noncurrent Liabilities	233.6	239.4	316.3	226.3	—	228.8
Equity	0.6	—	18.6	1.2	—	1.9
Total Liabilities and Equity	$ 284.8	$ 325.8	$ 615.1	$ 243.8	$ —	$ 259.0

(a) Includes an intercompany item eliminated in consolidation of $39 million.
(b) Includes an intercompany item eliminated in consolidation of $1 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, 2019

	Other Consolidated VIEs					
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Desert Sky and Trent**	**Apple Blossom and Black Oak**	**Santa Rita East**
	(in millions)					
ASSETS						
Current Assets	$ 842.8	$ 194.6	$ 25.8	$ 7.8	$ 10.1	$ 17.7
Net Property, Plant and Equipment	—	—	424.1	330.6	231.4	465.2
Other Noncurrent Assets	7.1	—	3.2	10.1	13.1	0.3
Total Assets	$ 849.9	$ 194.6	$ 453.1	$ 348.5	$ 254.6	$ 483.2
LIABILITIES AND EQUITY						
Current Liabilities	$ 805.2	$ 40.7	$ 192.4	$ 5.5	$ 5.4	$ 3.9
Noncurrent Liabilities	0.9	78.0	4.8	15.8	4.7	7.5
Equity	43.8	75.9	255.9	327.2	244.5	471.8
Total Liabilities and Equity	$ 849.9	$ 194.6	$ 453.1	$ 348.5	$ 254.6	$ 483.2

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

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, 2019, 2018 and 2017 were $55 million, $58 million and $61 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,			
	2019		2018	
	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	17.5	17.5	14.5	14.5
SWEPCo's Share of Obligations	—	130.0	—	167.6
Total Investment in DHLC	$ 25.1	$ 155.1	$ 22.1	$ 189.7

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2019, 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 are 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, 2019 and 2018, 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 of OVEC and the representation of the sponsoring companies on the Operating Committee under the intercompany power agreement.

AEP's investment in OVEC was:

	December 31,			
	2019		2018	
	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)	—	588.9	—	604.1
Total Investment in OVEC	$ 4.4	$ 593.3	$ 4.4	$ 608.5

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt was $213 million, $106 million and $270 million as of December 31, 2019 and $218 million, $109 million and $277 million as of December 31, 2018, 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:

Company	Years Ended December 31, 2019	2018	2017
		(in millions)	
APCo	$ 104.5	$ 100.4	$ 101.0
I&M	52.3	50.2	50.5
OPCo	132.7	127.5	128.2

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 filing of requests for rehearing did 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 was required to refund certain amounts that had been collected under its formula rate in its 2018 Projected Transmission Revenue Requirement. PATH-WV refunded $11 million in 2018, including carrying charges, related to the January 2017 order in its 2018 Projected Transmission Revenue Requirement.

In January 2019, the FERC issued an order stating that PATH complied in part, and did not comply in part, with directives of the previous FERC order’s mandated compliance filing concerning formula rates and its abandonment recovery. The order included a requirement for PATH to recalculate its recoverable cost of service associated with general advertising costs and provide information regarding land transactions. PATH filed an additional compliance filing, including refund estimates. In connection with its recalculated recoverable cost of service, PATH-WV will refund disallowed costs for general advertising that were previously collected in formula rates. As of December 31, 2019 PATH-WV has $1 million, including carrying charges, recorded as Accumulated Provisions for Rate Refunds that will be refunded in rates effective January 1, 2020.

In January 2020, the FERC issued an order on the PATH Companies' February 2017 request for rehearing. The order included: (a) a request for additional briefs to determine a just and reasonable ROE, (b) confirmation of a previous order stating that PATH's risk profile has decreased due to the PATH Project's abandonment and (c) acceptance of PATH's compliance filing from March 2017 as discussed above, subject to the review of (a). In addition, the order granted rehearing and reversed the disallowance of certain education, outreach and general advertising costs as discussed above. The January 2020 FERC order may be subject to further requests for rehearing or appeal.

AEP's investment in PATH-WV was:

	December 31,			
	2019		2018	
	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	(1.7)	(1.7)	(1.4)	(1.4)
Total Investment in PATH-WV	$ 17.1	$ 17.1	$ 17.4	$ 17.4

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	2019	2018	2017
	(in millions)		
AEP Texas	$ 206.6	$ 184.3	$ 152.6
AEPTCo	242.3	220.4	188.9
APCo	308.3	295.6	268.8
I&M	184.8	173.5	176.0
OPCo	230.4	214.9	195.7
PSO	125.7	121.5	114.7
SWEPCo	169.5	164.4	150.7

The carrying amount and classification of variable interest in AEPSC's accounts payable were as follows:

	December 31,							
	2019				2018			
Company	As Reported on the Balance Sheet		Maximum Exposure		As Reported on the Balance Sheet		Maximum Exposure	
	(in millions)							
AEP Texas	$	32.4	$	32.4	$	22.3	$	22.3
AEPTCo		33.4		33.4		24.6		24.6
APCo		44.1		44.1		32.2		32.2
I&M		28.6		28.6		23.8		23.8
OPCo		33.2		33.2		23.9		23.9
PSO		18.1		18.1		13.2		13.2
SWEPCo		23.4		23.4		18.4		18.4

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, 2019, 2018 and 2017 were $215 million, $238 million and $224 million, respectively. The carrying amounts of I&M's liabilities associated with AEGCo as of December 31, 2019 and 2018 were $10 million and $20 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.

Significant Equity Method Investments in Unconsolidated Entities

For a discussion of the equity method of accounting, see the "Equity Investment in Unconsolidated Entities" section of Note 1.

Sempra Renewables LLC

In April 2019, AEP acquired a 50% interest in five wind farms in multiple states as part of the purchase of Sempra Renewables LLC. The wind farms are joint ventures with BP Wind Energy who holds the other 50% interest. All five wind farms have long-term PPAs for 100% of their energy production. One of the jointly-owned wind farms has PPAs with I&M and OPCo for a portion of its energy production. Another jointly-owned wind farm has a PPA with SWEPCo for a portion of its energy production. The joint venture wind farms are not considered VIEs and AEP is not required to consolidate them as AEP does not have a controlling financial interest. However, AEP is able to exercise significant influence over the wind farms and therefore applies the equity method of accounting. As of December 31, 2019, AEP's investment in the five joint venture wind farms was $394 million. The investment includes amounts recognized in AOCI related to interest rate cash flow hedges. The investment is comprised of a historical investment of $420 million plus a basis difference of $(18) million. AEP's equity earnings associated with the five joint venture wind farms was a loss of $4 million for the year ended December 31, 2019. AEP recognized $27 million of PTC attributable to the joint venture wind farms for the year ended December 31, 2019, which was recorded in Income Tax Expense (Benefit) on the statements of income.

ETT

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 held a 49.5% interest in ETT and AEP Transmission Partner held the remaining 0.5% membership interest in ETT. In July 2019, AEP Transmission Partner was merged into AEP Transmission Holdco, increasing AEP Transmission Holdco's interest in ETT to 50%. As a result, AEP, through its wholly-owned subsidiary, holds a 50% membership interest in ETT. As of December 31, 2019 and 2018, AEP's investment in ETT was $695 million and $666 million, respectively. AEP's equity earnings associated with ETT were $66 million, $62 million and $82 million for the years ended December 31, 2019, 2018 and 2017 respectively.

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 balance sheets. The following tables include the total plant balances as of December 31, 2019 and 2018:

December 31, 2019	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 21,323.5	(a)	$ —	$ —	$ 6,563.7	$ 5,099.7	$ —	$ 1,574.6	$ 4,691.4	(a)
Transmission	24,763.4		4,466.5	8,137.9	3,584.1	1,641.8	2,686.3	948.5	2,056.5	
Distribution	22,440.8		4,215.2	—	4,201.7	2,437.6	5,323.5	2,684.8	2,270.7	
Other	4,369.6		803.4	268.2	542.0	590.9	754.7	337.2	520.6	
CWIP	4,261.2	(a)	763.9	1,485.7	593.4	382.3	394.4	133.4	210.1	(a)
Less: Accumulated Depreciation	18,778.1		1,465.0	402.3	4,425.6	3,281.4	2,261.7	1,579.9	2,766.2	
Total Regulated Property, Plant and Equipment - Net	58,380.4		8,784.0	9,489.5	11,059.3	6,870.9	6,897.2	4,098.6	6,983.1	
Nonregulated Property, Plant and Equipment - Net	1,757.7		61.1	1.4	22.6	28.8	9.8	4.7	112.1	
Total Property, Plant and Equipment - Net	$ 60,138.1		$ 8,845.1	$ 9,490.9	$ 11,081.9	$ 6,899.7	$ 6,907.0	$ 4,103.3	$ 7,095.2	

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	

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

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	2019 Annual Composite Depreciation Rate Ranges			2019 Depreciable Life Ranges (in years)			2018 Annual Composite Depreciation Rate Ranges			2018 Depreciable Life Ranges (in years)			2017 Annual Composite Depreciation Rate Ranges			2017 Depreciable Life Ranges (in years)		
Generation	2.5%	-	5.5%	20	-	132	2.4%	-	4.0%	20	-	132	2.3%	-	3.7%	20	-	132
Transmission	1.8%	-	2.6%	15	-	81	1.6%	-	2.7%	15	-	81	1.6%	-	2.7%	15	-	100
Distribution	2.7%	-	3.7%	7	-	78	2.7%	-	3.6%	7	-	78	2.7%	-	3.7%	5	-	156
Other	2.6%	-	9.5%	5	-	75	2.3%	-	9.8%	5	-	75	2.3%	-	9.2%	5	-	84

AEP Texas

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)			2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)			2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)		
Transmission	1.8%	45	-	81	1.7%	45	-	81	1.7%	45	-	81
Distribution	3.5%	7	-	70	3.6%	7	-	70	3.6%	7	-	70
Other	6.3%	5	-	50	6.0%	5	-	50	8.7%	5	-	50

AEPTCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)			2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)			2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)		
Transmission	2.0%	24	-	75	1.9%	20	-	75	1.7%	20	-	100
Other	5.8%	5	-	64	5.6%	5	-	64	6.7%	5	-	84

APCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)			2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)			2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)		
Generation	3.2%	35	-	118	3.1%	35	-	112	3.1%	35	-	112
Transmission	1.8%	15	-	71	1.6%	15	-	68	1.6%	15	-	68
Distribution	3.7%	12	-	57	3.6%	10	-	57	3.7%	10	-	57
Other	7.2%	5	-	55	7.4%	5	-	55	6.5%	5	-	55

I&M

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)			2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)			2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)		
Generation	4.0%	20	-	132	3.4%	20	-	132	2.4%	20	-	132
Transmission	1.9%	50	-	73	1.8%	50	-	73	1.7%	50	-	75
Distribution	3.4%	9	-	75	3.1%	9	-	75	2.7%	10	-	70
Other	9.4%	5	-	50	8.9%	5	-	50	8.4%	5	-	45

OPCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)			2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)			2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)		
Transmission	2.3%	39	-	60	2.3%	39	-	60	2.3%	39	-	60
Distribution	3.1%	14	-	65	3.0%	14	-	65	2.8%	5	-	57
Other	4.9%	5	-	50	6.3%	5	-	50	6.2%	5	-	50

PSO

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges
		(in years)		(in years)		(in years)
Generation	2.9%	35 - 75	2.9%	35 - 75	2.4%	35 - 85
Transmission	2.4%	45 - 75	2.3%	45 - 75	2.2%	45 - 100
Distribution	2.9%	15 - 78	2.9%	15 - 78	2.7%	27 - 156
Other	5.6%	5 - 64	6.3%	5 - 64	7.4%	5 - 84

SWEPCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges
		(in years)		(in years)		(in years)
Generation	2.5%	40 - 70	2.4%	40 - 70	2.3%	40 - 70
Transmission	2.4%	50 - 73	2.2%	50 - 73	2.3%	50 - 73
Distribution	2.7%	25 - 70	2.7%	25 - 70	2.7%	25 - 70
Other	7.6%	5 - 55	8.0%	5 - 55	7.2%	5 - 55

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 2019, 2018 and 2017.

Functional Class of Property	2019 Annual Composite Depreciation Rate Ranges	2019 Depreciable Life Ranges		2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges		2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges	
		(in years)			(in years)			(in years)	
Generation	3.2% - 21.2%	15 - 59		3.4% - 22.3%	15 - 59		2.4% - 5.1%	15 - 66	
Transmission	2.5%	30 - 40		2.4%	40		0.2%	40	
Distribution	2.3%	40		2.3%	40		2.3%	40	
Other	17.6%	5 - 50	(a)	16.3%	5 - 50	(a)	12.1%	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, wind farms, solar 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, 2019 and 2018, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.73 billion and $1.66 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2019 and 2018, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.65 billion and $2.16 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 2019 and 2018 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2018	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2019
			(in millions)			
AEP (b)(c)(d)(e)	$ 2,355.5	$ 102.5	$ 12.0	$ (118.1)	$ 67.0	$ 2,418.9
AEP Texas (b)(e)	27.9	1.3	—	(0.2)	0.1	29.1
APCo (b)(e)	116.1	5.9	—	(17.6)	6.7	111.1
I&M (b)(c)(e)	1,681.3	67.4	—	(0.2)	0.1	1,748.6
OPCo (e)	1.8	0.1	—	(0.3)	0.2	1.8
PSO (b)(e)	46.9	3.1	—	(0.4)	2.6	52.2
SWEPCo (b)(d)(e)	206.8	10.3	—	(11.8)	6.9	212.2

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

(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 $1.73 billion and $1.66 billion as of December 31, 2019 and 2018, 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:

	Years Ended December 31,		
Company	**2019**	**2018**	**2017**
		(in millions)	
AEP	$ 168.4	$ 132.5	$ 93.7
AEP Texas	15.2	20.0	6.8
AEPTCo	84.3	70.6	49.0
APCo	16.6	13.2	9.2
I&M	19.4	11.9	11.1
OPCo	18.2	9.8	6.4
PSO	2.7	0.4	0.5
SWEPCo	6.8	6.0	2.4

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

	Years Ended December 31,		
Company	**2019**	**2018**	**2017**
		(in millions)	
AEP	$ 88.7	$ 73.6	$ 48.6
AEP Texas	20.0	18.4	6.8
AEPTCo	32.2	26.1	20.2
APCo	9.3	8.4	5.3
I&M	8.9	7.4	6.7
OPCo	6.7	5.8	3.8
PSO	1.9	0.9	1.1
SWEPCo	4.0	4.8	2.1

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 nonaffiliated 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, 2019		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a)(h)	Coal	83.5%	$ —	$ —	$ —
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	337.3	6.2	216.5
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	374.3	3.4	101.1
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	607.8	7.7	416.8
Oklaunion Power Station (e)	Coal	70.3%	106.6	0.1	91.7
Turk Generating Plant (g)	Coal	73.3%	1,593.3	1.7	225.8
Total			$ 3,019.3	$ 19.1	$ 1,051.9
AEP Texas					
Oklaunion Power Station (e)	Coal	54.7%	$ 351.7	$ —	$ 291.9
I&M					
Rockport Generating Plant (b)(c)(d)	Coal	50.0%	$ 1,114.2	$ 105.5	$ 586.2
PSO					
Oklaunion Power Station (e)	Coal	15.6%	$ 106.6	$ 0.1	$ 91.7
SWEPCo					
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	$ 337.3	$ 6.2	$ 216.5
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	374.3	3.4	101.1
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	607.8	7.7	416.8
Turk Generating Plant (g)	Coal	73.3%	1,593.3	1.7	225.8
Total			$ 2,912.7	$ 19.0	$ 960.2

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2018 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a)(h)	Coal	83.5%	$ 16.4	$ 0.2	$ 2.4
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	336.2	5.1	209.6
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	591.3	16.6	418.0
Oklaunion Power Station (e)	Coal	70.3%	106.4	—	67.8
Turk Generating Plant (g)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 3,015.9	$ 24.6	$ 984.2
AEP Texas					
Oklaunion Power Station (e)	Coal	54.7%	$ 352.1	$ 0.2	$ 218.6
I&M					
Rockport Generating Plant (b)(c)(d)	Coal	50.0%	$ 1,108.7	$ 50.2	$ 514.1
PSO					
Oklaunion Power Station (e)	Coal	15.6%	$ 106.4	$ —	$ 67.8
SWEPCo					
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	$ 336.2	$ 5.1	$ 209.6
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	591.3	16.6	418.0
Turk Generating Plant (g)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 2,893.1	$ 24.4	$ 914.0

(a) Operated by AGR.
(b) Operated by I&M.
(c) 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 nonaffiliated company. See the "Rockport Lease" section of Note 13.
(d) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.
(e) Operated by PSO, which owns 15.6%. Also jointly-owned (54.7%) by AEP Texas and various nonaffiliated companies.
(f) Operated by CLECO, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Conesville Generating Station, Unit 4 was impaired as of December 31, 2019. See the "Impairments" section of Note 7.

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, 2019 and 2018 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
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
Impairment Losses	—	—	—
Balance as of December 31, 2019	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2019 and 2018, 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, 2019						
	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	$ 3,643.7	$ 2,069.9	$ —	$ —	$ —	$ —	$ 5,713.6
Commercial Revenues	2,155.3	1,152.9	—	—	—	—	3,308.2
Industrial Revenues	2,179.0	429.1	—	—	—	(0.9)	2,607.2
Other Retail Revenues	179.1	43.8	—	—	—	—	222.9
Total Retail Revenues	8,157.1	3,695.7	—	—	—	(0.9)	11,851.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues (b)	807.6	—	—	254.8	—	—	1,062.4
Transmission Revenues (a)	292.1	435.1	1,077.2	—	—	(825.0)	979.4
Renewable Generation Revenues (c)	—	—	—	57.3	—	—	57.3
Retail, Trading and Marketing Revenues (b)	—	—	—	1,480.7	—	(135.6)	1,345.1
Total Wholesale and Competitive Retail Revenues	1,099.7	435.1	1,077.2	1,792.8	—	(960.6)	3,444.2
Other Revenues from Contracts with Customers (c)	168.2	169.4	16.6	4.9	104.7	(147.1)	316.7
Total Revenues from Contracts with Customers	9,425.0	4,300.2	1,093.8	1,797.7	104.7	(1,108.6)	15,612.8
Other Revenues:							
Alternative Revenues (c)	(57.9)	32.3	(20.6)	—	—	(66.9)	(113.1)
Other Revenues (c)	—	150.0	—	59.9	(8.9)	(139.3)	61.7
Total Other Revenues	(57.9)	182.3	(20.6)	59.9	(8.9)	(206.2)	(51.4)
Total Revenues	$ 9,367.1	$ 4,482.5	$ 1,073.2	$ 1,857.6	$ 95.8	$ (1,314.8)	$ 15,561.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $794 million. The remaining affiliated amounts were immaterial.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $136 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues.

	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	$ 2,189.4	$ —	$ —	$ —	$ —	$ 5,941.2
Commercial Revenues	2,183.4	1,251.7	—	—	—	—	3,435.1
Industrial Revenues	2,212.8	512.5	—	—	—	—	2,725.3
Other Retail Revenues	183.5	42.7	—	—	—	—	226.2
Total Retail Revenues (a)	8,331.5	3,996.3	—	—	—	—	12,327.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues (d)	899.8	—	—	423.7	—	(7.3) (e)	1,316.2
Transmission Revenues (b)	282.2	372.1	849.3	—	—	(737.1)	766.5
Renewable Generation Revenues (d)	—	—	—	50.8	—	—	50.8
Retail, Trading and Marketing Revenues (c)	—	—	—	1,422.9	—	(120.7)	1,302.2
Total Wholesale and Competitive Retail Revenues	1,182.0	372.1	849.3	1,897.4	—	(865.1)	3,435.7
Other Revenues from Contracts with Customers (d)	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	(897.1)	16,216.5
Other Revenues:							
Alternative Revenues (d)	(15.9)	(22.2)	(60.4)	—	—	52.7	(45.8)
Other Revenues (d)	(10.5)	102.3	—	22.3	8.9	(98.0) (e)	25.0
Total Other Revenues	(26.4)	80.1	(60.4)	22.3	8.9	(45.3)	(20.8)
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7

(a) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(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 affiliated revenue for Generation & Marketing was $121 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.
(e) 2018 amounts have been revised to reflect the reclassification of $98 million of affiliated revenues between Generation Revenues and Other Revenues. This reclassification did not impact previously reported Total Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 571.5	$ —	$ 1,266.9	$ 730.0	$ 1,502.0	$ 650.2	$ 638.6
Commercial Revenues	411.5	—	559.9	494.2	738.5	388.5	485.4
Industrial Revenues	129.4	—	592.2	550.7	299.9	303.5	338.7
Other Retail Revenues	29.9	—	75.2	7.3	13.1	81.6	9.0
Total Retail Revenues	1,142.3	—	2,494.2	1,782.2	2,553.5	1,423.8	1,471.7
Wholesale Revenues:							
Generation Revenues (a)	—	—	251.5	402.4	—	39.5	194.7
Transmission Revenues (b)	379.2	1,025.5	103.6	25.1	56.0	27.5	106.7
Total Wholesale Revenues	379.2	1,025.5	355.1	427.5	56.0	67.0	301.4
Other Revenues from Contracts with Customers (c)	30.1	16.6	61.8	98.4	139.3	22.0	26.1
Total Revenues from Contracts with Customers	1,551.6	1,042.1	2,911.1	2,308.1	2,748.8	1,512.8	1,799.2
Other Revenues:							
Alternative Revenues (d)	0.6	(20.7)	13.6	(1.4)	31.7	(31.0)	(48.3)
Other Revenues (d)	157.1	—	—	—	17.1	—	—
Total Other Revenues	157.7	(20.7)	13.6	(1.4)	48.8	(31.0)	(48.3)
Total Revenues	$ 1,709.3	$ 1,021.4	$ 2,924.7	$ 2,306.7	$ 2,797.6	$ 1,481.8	$ 1,750.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $129 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 $782 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $73 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.

	Year Ended December 31, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 578.9	$ —	$ 1,342.7	$ 730.0	$ 1,611.6	$ 659.0	$ 641.6
Commercial Revenues	414.7	—	580.4	485.0	835.6	394.2	483.9
Industrial Revenues	128.0	—	604.3	565.6	385.2	304.0	333.7
Other Retail Revenues	29.4	—	77.4	7.2	12.9	83.6	8.6
Total Retail Revenues (a)	1,151.0	—	2,604.8	1,787.8	2,845.3	1,440.8	1,467.8
Wholesale Revenues:							
Generation Revenues (b)	—	—	250.4	470.5	—	36.3	216.8
Transmission Revenues (c)	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 (d)	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 (e)	(1.3)	(55.9)	(23.8)	(2.1)	(20.8)	10.9	4.9
Other Revenues (e)	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) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

(b) 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.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $646 million. The remaining affiliated amounts were immaterial.

(d) 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.

(e) 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 PPA. 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 transmission owner 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, 2019. 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	2020	2021-2022	2023-2024	After 2024	Total
			(in millions)		
AEP	$ 953.0	$ 160.8	$ 160.6	$ 223.5	$ 1,497.9
AEP Texas	387.0	—	—	—	387.0
AEPTCo	1,090.7	—	—	—	1,090.7
APCo	158.0	32.3	23.2	11.6	225.1
I&M	29.6	8.8	8.8	4.4	51.6
OPCo	61.0	—	—	—	61.0
PSO	11.7	—	—	—	11.7
SWEPCo	30.4	—	—	—	30.4

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, 2019 and 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, 2019 and 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, 2019 and 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	Years Ended December 31, 2019	2018
	(in millions)	
AEPTCo	$ 65.9	$ 58.6
APCo	47.3	52.5
I&M	37.1	35.3
OPCo	33.9	46.1
PSO	9.7	12.4
SWEPCo	17.6	16.3

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, 2019 and 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	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
March 31, 2019								
Total Revenues	$ 4,056.8	$ 390.7	$ 243.5	$ 792.8	$ 614.3	$ 836.8	$ 332.8	$ 421.1
Operating Income	788.4	70.8	141.6	152.1	115.0	162.5	20.9	54.1
Net Income	574.1	34.4	104.3	133.7	98.9	128.0	6.2	29.0
Earnings Attributable to Common Shareholders	572.8	NA	NA	NA	NA	NA	NA	27.8
June 30, 2019								
Total Revenues	$ 3,573.6	$ 438.0	$ 266.9	$ 655.8	$ 543.1	$ 606.6	$ 348.1	$ 375.5
Operating Income	551.0	38.7	161.0	76.9	77.9	77.1	56.6	33.0
Net Income	459.1	80.6	136.0	55.5	60.3	50.6	41.9	7.3
Earnings Attributable to Common Shareholders	461.3	NA	NA	NA	NA	NA	NA	6.2
September 30, 2019								
Total Revenues	$ 4,315.0	$ 489.3	$ 259.7	$ 755.5	$ 611.1	$ 710.6	$ 493.0	$ 545.5
Operating Income	958.2	118.2	142.3	142.6	107.3	98.6	120.0	134.7
Net Income	733.9	77.0	107.6	104.3	88.8	69.1	100.3	111.3
Earnings Attributable to Common Shareholders	733.5	NA	NA	NA	NA	NA	NA	110.5
December 31, 2019								
Total Revenues	$ 3,616.0	$ 391.3	$ 251.3	$ 720.6	$ 538.2	$ 643.6	$ 307.9	$ 408.8
Operating Income	294.7	4.3	122.3	25.7	40.6	63.0	1.8	33.9
Net Income (Loss)	152.7	(13.7)	91.8	12.8	21.4	49.4	(10.8)	14.6
Earnings Attributable to Common Shareholders	153.5	NA	NA	NA	NA	NA	NA	14.1

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo	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

NA Not applicable.

AEP

The unaudited quarterly financial information relating to Common Shareholders is as follows:

	2019 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders (in millions)	$ 572.8	$ 461.3	$ 733.5	$ 153.5
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.16	0.93	1.49	0.31
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.16	0.93	1.48	0.31

	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

(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 505005
Louisville, KY 40233-5005
For overnight deliveries:
Computershare Trust Company, N.A.
462 South 4th Street
Louisville, KY 40202
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 Darcy Reese, 614-716-2614, dlreese@aep.com; Individual shareholders should contact Rhonda Owens-Paul, 614-716-2819, rkowens-paul@AEP.com.

Number of Shareholders - As of February 24, 2020, there were approximately 57,000 registered shareholders and approximately 870,000 shareholders holding stock in street name through a bank or broker. There were 494,832,744 shares outstanding as of February 24, 2020.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2019. 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	59	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	54	Executive Vice President - Utilities
Paul Chodak, III	56	Executive Vice President - Generation
David M. Feinberg	50	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	59	Executive Vice President and Chief Administrative Officer
Mark C. McCullough	60	Executive Vice President - Transmission
Charles R. Patton	60	Executive Vice President - External Affairs
Brian X. Tierney	52	Executive Vice President and Chief Financial Officer
Charles E. Zebula	59	Executive Vice President - Energy Supply

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