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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **March 31, 2020**
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Trading Symbol	Name of Each Exchange on Which Registered
American Electric Power Company Inc	Common Stock, $6 50 par value	AEP	New York Stock Exchange
American Electric Power Company Inc	6 125% Corporate Units	AEP PR B	New York Stock Exchange

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days

Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232 405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit such files)

Yes ☒ No ☐

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

Large Accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Smaller reporting company ☐ Emerging growth company ☐

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

Large Accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Smaller reporting company ☐ Emerging growth company ☐

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

☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☒

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

	Number of shares of common stock outstanding of the Registrants as of May 6, 2020
American Electric Power Company, Inc.	495,583,133
	($6.50 par value)
AEP Texas Inc.	*100*
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

(a) 100% interest is held by AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of American Electric Power Company, Inc.
NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
March 31, 2020

Part II. OTHER INFORMATION

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
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.
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 Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AMI	Advanced Metering Infrastructure.
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 VIE 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 rate-making purposes.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
Cardinal Operating Company	A jointly-owned organization between AGR and a nonaffiliate. The nonaffiliate operates the three unit Cardinal Plant and wholly-owns Units 2 and 3.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.
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 VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.

Term	Meaning
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE 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.
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 Fuel Adjustment Clause Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
MISO	Midcontinent Independent 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.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.

Term	Meaning
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated VIE 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.
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.
PATH-WV	PATH West Virginia Transmission Company, LLC, a joint venture owned 50% by FirstEnergy and 50% by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
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.
Reference Rate Reform	The global transition away from referencing the London Interbank Offered Rate and other interbank offered rates, and toward new reference rates that are more reliable and robust.
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.
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.
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 VIE 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 302.4 MW wind generation facility in west Texas in which AEP owns a 75% interest.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.

Term	Meaning
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated VIEs formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The project included the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2019 Annual Report, 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.
- The impact of pandemics, including COVID-19, and any associated disruption of AEP's business operations due to impacts on economic or market conditions, electricity usage, employees, customers, service providers, vendors and suppliers.
- 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. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2019 Annual Report and in Part II of this report.

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

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

EXECUTIVE OVERVIEW

COVID-19

In March 2020, COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. Its rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions significantly disrupted economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. As of March 31, 2020, the reduction in the demand for energy did not materially impact the Registrants' financial statements. However, if the severity of the economic disruptions increase as the duration of the COVID-19 pandemic continues, the negative financial impact due to reduced demand could be significantly greater in future periods than in the first quarter.

AEP's electric utility operating companies informed both retail customers and state regulators that disconnections for non-payment have been temporarily suspended. These uncertain economic conditions may result in the inability of customers to pay for electric service, which could affect the collectability of the Registrants' revenues and adversely affect financial results. The Registrants are evaluating and working with their state regulatory commissions on potential rate recovery mechanisms for increased costs incurred due to COVID-19. Certain Registrants received orders approving the deferral of certain incremental expenses associated with COVID-19. See Note 4 - Rate Matters for additional information. The Registrants have not observed a material change in their typical collections experience and thus did not materially adjust their allowances for uncollectible accounts as of March 31, 2020.

The effects of the continued outbreak of COVID-19 and related government responses could also include extended disruptions to supply chains and capital markets, reduced labor availability and a prolonged reduction in economic activity. These effects could have a variety of adverse impacts to the Registrants, including their ability to operate their facilities. As of March 31, 2020, there were no material adverse impacts to the Registrants' operations due to COVID-19.

In addition, the economic disruptions caused by COVID-19 could also adversely impact the impairment risks for certain long-lived assets, equity method investments and goodwill. AEP evaluated these impairment considerations and determined that no such impairments occurred as of March 31, 2020.

During the first quarter of 2020, AEP increased its liquidity position to mitigate the risk of market volatility due to COVID-19. The Registrants' access to funding was limited for a period of time during the first quarter and therefore AEP entered into a 364–day term loan to reduce reliance on commercial paper and help mitigate potential future liquidity risks. Specifically, for the first three months of 2020, AEP issued approximately $1.4 billion in long-term debt and $1.6 billion in short-term debt primarily via a 364-day term loan to enhance the Registrants' available liquidity. As of March 31, 2020, AEP's available liquidity is $2.8 billion. Management believes the Registrants have adequate liquidity under existing credit facilities. To the extent that future access to the capital markets or the cost of funding is adversely affected by COVID-19, the Registrants may need to consider alternative sources of funding for operations and working capital, which may adversely impact future results of operations, financial condition, and cash flows.

The effects of an extended disruption to the supply chains could disrupt or delay construction, testing, supervisory and support activities at renewable generation facilities, in particular, the North Central Wind Energy Facilities and the AEP Generation & Marketing segment's Flat Ridge 3 wind project. The in-service dates for the North Central Wind Energy Facilities are scheduled for end of year 2020 for one project, and end of year 2021 for the remaining two projects. Under the terms of the Purchase and Sales Agreement, PSO and SWEPCo do not have an obligation to acquire the North Central Wind Energy Facility projects if the projects are not completed by the required in-service dates. The in-service date for the Flat Ridge 3 wind project is scheduled for end of the year 2020. As of March 31, 2020, there has been no material adverse impacts to either the North Central Wind Energy Facility or the Flat Ridge 3 project. AEP currently expects the construction projects to be delivered on-time in accordance with the agreements with the developers. However, depending on the longevity and ultimate impact of COVID-19, future delays in the construction of AEP's renewable assets could occur which could impact the current construction schedule, budget, and the qualification for federal PTC. AEP is working with industry groups on potential legislative and administrative relief for a PTC continuity safe harbor extension due to the ongoing impacts of COVID-19.

In March 2020, President Trump signed into law legislation referred to as the "Coronavirus Aid, Relief, and Economic Security Act" (the CARES Act). The CARES Act includes tax relief provisions such as: (a) an Alternative Minimum Tax (AMT) Credit Refund, (b) a 5-year net operating losses (NOL) carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. As of March 31, 2020, AEP has a $20 million AMT credit refund recognized in anticipation of a refund from the U.S. Treasury. Management is evaluating the ability to recover taxes paid in 2014 under the 5-year NOL carryback provision. The Registrants currently expect to defer payments of the employer share of payroll taxes for the period March 27, 2020 through December 31, 2020 and pay 50% of the obligation by December 31, 2021 and the remaining 50% by December 31, 2022.

The Registrants are taking steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19. The Registrants have updated and implemented a company-wide pandemic plan to address specific aspects of the COVID-19. This plan guides emergency response, business continuity, and the precautionary measures AEP is taking on behalf of its employees and the public. The Registrants have taken extra precautions for employees who work in the field and for employees who work in their facilities, and have implemented work from home policies where appropriate. The Registrants will continue to monitor developments affecting both their workforce and customers, and will take additional precautions that management determines are necessary in order to mitigate the impacts. AEP continues to focus on providing safe, uninterrupted service to its customers, which includes the implementation of strong physical and cyber-security measures to ensure that its systems remain functional with a partially remote workforce. As of March 31, 2020, there has been no material adverse impact to the Registrants' business operations and customer service due to remote work. Management will continue to review and modify plans as conditions change. Despite efforts to manage these impacts to the Registrants, the ultimate impact of COVID-19 also depends on factors beyond management's knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, management cannot estimate the potential future impact to financial position, results of operations and cash flows, but the impacts could be material.

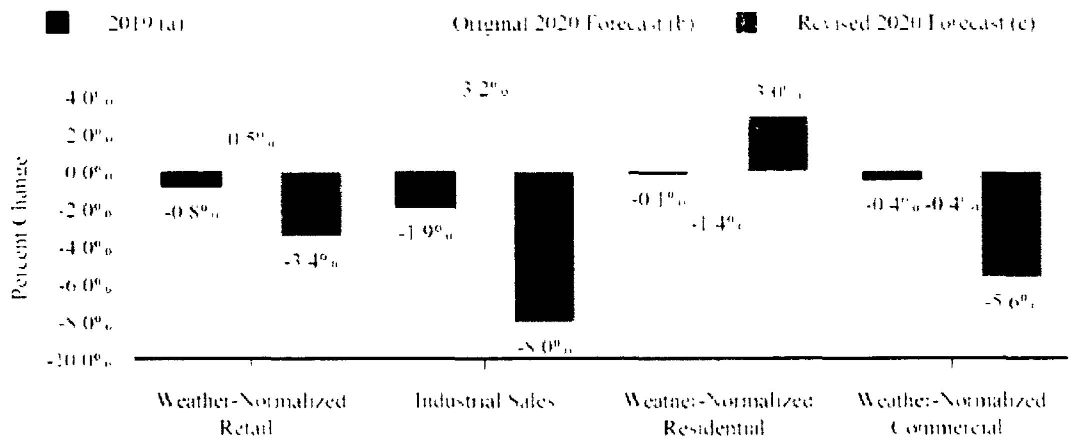
Customer Demand

AEP's weather-normalized retail sales volumes for the first quarter of 2020 decreased by 0.7% from the first quarter of 2019. AEP's first quarter 2020 industrial sales volumes decreased by 0.7% compared to the first quarter of 2019. The decline in industrial sales was spread across many industries. Weather-normalized residential sales decreased 1.2% while weather-normalized commercial sales were flat in the first quarter of 2020, from the first quarter of 2019.

Many businesses were forced to limit or reduce their operations in response to the COVID-19 outbreak over the last two weeks of the first quarter of 2020. While there is uncertainty regarding the duration and total impact that COVID-19 will have on AEP's retail sales in 2020, AEP expects COVID-19 to have a larger impact in the second quarter of 2020 than it had in the first quarter.

As a result of the impact of COVID-19, AEP revised its forecast for 2020 weather-normalized retail sales volumes from the forecast presented in the 2019 10-K. In 2020, AEP currently anticipates weather-normalized retail sales volumes will decrease by 3.4%. AEP expects industrial class sales volumes to decrease by 8% in 2020, while weather-normalized residential sales volumes are projected to increase by 3%. Finally, AEP currently projects weather-normalized commercial sales volumes to decrease by 5.6%.

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) As presented in the 2019 AEP 10-K Forecasted percentage change for the year ended December 31, 2020 compared to the year ended December 31, 2019
(c) Revised for the impact of COVID-19 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 Indiana Base Rate Case* - In May 2019, I&M filed a request with the IURC for a $172 million annual increase based upon a proposed 10.5% return on common equity. In March 2020, the IURC issued an order authorizing a $77 million annual base rate increase based upon a return on common equity of 9.7% effective March 2020. This increase will be phased in through January 2021 with an approximate $44 million annual increase in base rates effective March 2020 and the full $77 million annual increase effective January 2021. The order rejected I&M's proposed re-allocation of capacity costs related to the loss of a significant FERC wholesale contract, which will negatively impact I&M's annual pretax earnings by approximately $20 million starting June 2020. The IURC also rejected I&M's proposed AMI meter rider. In March 2020, I&M filed for rehearing as a result of the IURC's ruling to reject I&M's proposed re-allocation of capacity costs. Intervenors subsequently filed objections to I&M's appeal. In April 2020, I&M filed a reply to these objections on rehearing and appealed the IURC's order.

- *2017-2019 Virginia Triennial Review* - In March 2020, APCo submitted its 2017-2019 Virginia triennial earnings review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $65 million annual increase based upon a proposed 9.9% return on common equity. 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. 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. 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.

- *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 the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court. As of March 31, 2020, 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.

- In April 2020, the Virginia Clean Economy Act was signed into law by the Virginia Governor. The law will become effective July 2020 and includes requirements for Virginia electric utilities to: (a) retire no later than 2045 all electric generating units located in Virginia that emit carbon as a by-product, (b) produce 100% of the company's power to serve Virginia customers from renewable sources by 2050 with increasing percentages of mandatory renewable energy sources each year and (c) achieve increasing annual energy efficiency savings from 2022-2025 using 2019 as the base year. This law also provides that if the Virginia SCC finds in any triennial review that revenue reductions related to energy efficiency programs approved and deployed since the utility's previous triennial review have caused the utility to earn more than 70 basis points below its authorized rate of return, the Virginia SCC shall order increases to the utility's rates necessary to recover such revenue reductions. If any of these costs are not recoverable, 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 2020. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (Decrease)		Approved ROE	New Rates Effective
		(in millions)			
I&M	Indiana	$ 77.4	(a)	9.7%	March 2020
AEP Texas	Texas	(40.0)	(b)	9.4%	June 2020

(a) This increase will be phased in through January 2021 with an approximate $44 million annual increase in base rates effective March 2020 and the full $77 million annual increase effective January 2021. In March 2020, I&M filed for rehearing as a result of the IURC's ruling to reject I&M's proposed re-allocation of capacity costs.
(b) In April 2020, the PUCT issued an order approving the stipulation and settlement agreement with a capital structure of 57.5% debt and 42.5% common equity effective with the first billing cycle in June 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)		
APCo	Virginia	March 2020	$ 64.9	9.9%	(a)

(a) Commission Staff/Intervenor direct testimony to be filed by August 2020.

Renewable Generation

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

Contracted Renewable Generation Facilities

AEP continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy technologies. The Generation & Marketing segment also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties.

As of March 31, 2020, subsidiaries within AEP's Generation & Marketing segment had approximately 1,423 MWs of contracted renewable generation projects in-service. In addition, as of March 31, 2020, these subsidiaries had approximately 160 MWs of renewable generation projects under construction with total estimated capital costs of $235 million related to these projects.

Regulated Renewable Generation Facilities

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; the PSO agreement was approved by the Oklahoma Commission in February 2020. In January 2020, SWEPCo reached a joint settlement agreement with the APSC, Arkansas Attorney General's office and Walmart, Inc. Hearings in the Texas proceeding took place in February 2020. In April 2020, SWEPCo reached a joint settlement agreement with Louisiana Staff, Walmart, Inc. and the Alliance for Affordable Energy. In May 2020, the Arkansas Commission approved the settlement agreement as filed, with the exception that SWEPCo use its formula rate rider to recover its costs rather than the requested rider. SWEPCo is seeking regulatory approvals by July 2020.

Hydroelectric Generation

Evaluating Sale of Hydroelectric Generation

In March 2020, management placed 10 hydroelectric generation plants under study for a potential sale. The table below shows the net book value of each plant, including CWIP and materials and supplies, before cost of removal of the plants included in the study.

Owner	Plant Name	Units	State	Net Book Value as of March 31, 2020	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
				(in millions)		
AGR	Racine	2	OH	$ 43.2	48	1982
APCo	London	3	WV	9.6	14	1935
APCo	Marmet	3	WV	11.0	14	1935
APCo	Winfield	3	WV	13 9	15	1938
I&M	Berrien Springs	12	MI	7.7	6	1908
I&M	Buchanan	10	MI	5 1	3	1919
I&M	Constantine	4	MI	2.6	1	1921
I&M	Elkhart	3	IN	5 5	3	1913
I&M	Mottville	4	MI	2 9	2	1923
I&M	Twin Branch Hydro	8	IN	7 1	5	1904
	Total			$ 108.6	111	

If management decides to proceed with the sale of these plants, FERC approval would be required. In addition, for all plants, except for Racine, state commission approval would be required. Management currently estimates that any potential sale of these plants would not be completed until late 2020 at the earliest. There is no assurance that management will be able to sell any of these plants.

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. DHLC provides 100% of the fuel supply to Dolet Hills Power Station. In March 2020, it was determined that DHLC would not proceed developing additional mining areas for future lignite extraction and management notified a substantial portion of its workforce that employment will permanently end in June 2020. Based on these actions, management has revised the estimated useful life of many of DHLC's assets to June 2020 to coincide with the date at which extraction is expected to be discontinued. Management also revised the useful life of the Dolet Hills Power Station to September 2021 based on the remaining estimated fuel supply available for continued seasonal operation. In March 2020, primarily due to the revision in the useful life of DHLC, SWEPCo recorded a revision to increase estimated ARO liabilities by $21 million. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the pending cessation of lignite mining in June 2020.

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 $151 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 March 31, 2020, DHLC has unbilled lignite inventory and fixed costs of $124 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 March 31, 2020, Oxbow has unbilled fixed costs of $26 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.

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. In March 2020, as a follow-up to its 2019 Notice of Inquiry regarding transmission incentives policy, FERC issued a Notice of Proposed Rulemaking and requested comments by July 2020. AEP will file comments and monitor this proceeding. 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 5 – 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 the denial to those claims have been appealed to the AEP System Retirement Plan Appeal Committee. 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 March 31, 2020, 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 March 31, 2020.

Company	Plant Name and Unit	Generating Capacity	Amounts Pending Regulatory Approval	
		(in MWs)	(in millions)	
APCo (a)	Kanawha River Plant	400	$	14.0
APCo (b)	Clinch River Plant	705		25.3
APCo (a)	Sporn Plant, Units 1 and 3	300		2.0
APCo (a)	Glen Lyn Plant	335		3.4
SWEPCo (c)	Welsh Plant, Unit 2	528		35.5
Total		2,268	$	80.2

(a) Remaining amounts pending regulatory approval represent the FERC and the West Virginia jurisdictional share.
(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.

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 (SCR) 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 (DSI) 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.

In April 2020, an employee at the Rockport Plant was diagnosed with COVID-19. Several contract workers stopped working on the SCR project at Rockport Unit 2, and the project workforce reported an increased rate of absenteeism. I&M has notified the parties to the consent decree of this force majeure event and estimates that the date for completion of the SCR and DSI projects will be extended by approximately two weeks past the June 1, 2020 deadline. Management will continue to oversee the project through completion in light of these challenges.

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. A proposed rule to retain the existing PM standards was released in April 2020. 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 certain 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. In April 2020, the Federal EPA released a final rule adopting the conclusions set forth in the proposal and retaining the existing MATS standards.

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. In April 2020, Virginia enacted clean energy legislation to allow the state to participate in the Regional Greenhouse Gas Initiative, require the retirement of all fossil-fueled generation by 2045 and require 100% renewable energy to be provided to Virginia customers by 2050. 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. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit based on its determination that discharges from an injection well that make their way to the Pacific Ocean through ground water may require a permit if the distance traveled through ground water, length of time to reach the surface water and other factors make it "functionally equivalent" to a direct discharge from a point source. The second case was also remanded to the lower court. Prior to the Supreme Court's decision, 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 these developments 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 March 2020, Virginia's Governor signed House Bill 443 (HB 443) requiring APCo to close ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. APCo's current ARO for these units is based on closure in place and will require future revision to reflect the costs of closure by removal. As of March 31, 2020, APCo is unable to reasonably estimate this cost. Management expects to record a material revision to the ARO after engineering plans for the removal are developed later in 2020. The closure is required to be completed within 15 years from the start of the excavation process. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause (E-RAC). APCo may begin deferring incurred costs on July 1, 2020 and recovering these costs through the E-RAC beginning July 1, 2022. APCo is permitted to record carrying costs on the unrecovered balance of closure costs at a weighted average cost of capital approved by the Virginia SCC. HB 443 also allows any closure costs allocated to non-Virginia jurisdictional customers, but not collected from such non-Virginia jurisdictional customers, to be recovered from Virginia jurisdictional customers through the E-RAC. Management does not expect HB 443 to materially impact results of operations or cash flows, but does anticipate a material impact to APCo's balance sheet.

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 participate in rulemaking activities and make adjustments based on new federal and state requirements affecting its ash disposal units.

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. The final replacement rule was published in the Federal Register in April 2020 and will become effective in June 2020. The final rule limits the scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, artificial ponds and waste treatment systems.

In April 2020, the U.S. District Court for the District of Montana issued a decision vacating the U.S. Army Corps of Engineers' (Corps) General Nationwide Permit 12 (NWP 12), which provides standard conditions governing linear utility projects in streams, wetlands and other waters of the United States having minimal adverse environmental impacts. The Court found that in reissuing NWP 12 in 2017, the Corps failed to comply with Section 7 of the Endangered Species Act (ESA), which requires the Corps to consult with the U.S. Fish and Wildlife Service regarding potential impacts on endangered species. The Court remanded the permit back to the Corps to complete its ESA consultation, and also enjoined the Corps from authorizing any dredge or fill activities under NWP 12 pending completion of the consultation process. The Department of Justice filed a motion to stay the injunction and tailor the remedy imposed by the Court, and the court ordered the parties to file briefs on the issue in May 2020. Management is monitoring the litigation and evaluating other permitting alternatives, but is currently unable to predict the impact of this decision on current and planned projects.

RESULTS OF OPERATIONS

SEGMENTS

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

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

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

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

	Three Months Ended March 31, 2020	2019
	(in millions)	
Vertically Integrated Utilities	$ 245.3	$ 302.4
Transmission and Distribution Utilities	116.2	156.5
AEP Transmission Holdco	140.6	124.2
Generation & Marketing	28.4	40.1
Corporate and Other	(35.3)	(50.4)
Earnings Attributable to AEP Common Shareholders	$ 495.2	$ 572.8

AEP CONSOLIDATED

First Quarter of 2020 Compared to First Quarter of 2019

Earnings Attributable to AEP Common Shareholders decreased from $573 million in 2019 to $495 million in 2020 to primarily due to:

- A decrease in weather-related usage.
- A one-time reversal of a regulatory provision in 2019.

These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended March 31, 2020	2019
	(in millions)	
Revenues	$ 2,226.7	$ 2,403.3
Fuel and Purchased Electricity	671.2	856.4
Gross Margin	1,555.5	1,546.9
Other Operation and Maintenance	691.3	690.1
Depreciation and Amortization	381.7	356.3
Taxes Other Than Income Taxes	117.1	116.0
Operating Income	365.4	384.5
Other Income	1.6	1.3
Allowance for Equity Funds Used During Construction	8.2	10.7
Non-Service Cost Components of Net Periodic Benefit Cost	16.9	17.0
Interest Expense	(144.5)	(139.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings	247.6	274.5
Income Tax Expense (Benefit)	2.1	(28.4)
Equity Earnings of Unconsolidated Subsidiary	0.8	0.7
Net Income	246.3	303.6
Net Income Attributable to Noncontrolling Interests	1.0	1.2
Earnings Attributable to AEP Common Shareholders	$ 245.3	$ 302.4

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	8,262	9,216
Commercial	5,366	5,633
Industrial	8,475	8,545
Miscellaneous	530	546
Total Retail	22,633	23,940
Wholesale (a)	3,618	5,804
Total KWhs	26,251	29,744

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended March 31,	
	2020	**2019**
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,241	1,571
Normal – Heating (b)	1,611	1,595
Actual – Cooling (c)	13	1
Normal – Cooling (b)	5	5
Western Region		
Actual – Heating (a)	649	941
Normal – Heating (b)	867	866
Actual – Cooling (c)	51	11
Normal – Cooling (b)	28	28

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

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

First Quarter of 2019	$	302.4
Changes in Gross Margin:		
Retail Margins		5.9
Margins from Off-system Sales		(5.2)
Transmission Revenues		6.1
Other Revenues		1.8
Total Change in Gross Margin		8.6
Changes in Expenses and Other:		
Other Operation and Maintenance		(1.2)
Depreciation and Amortization		(25.4)
Taxes Other Than Income Taxes		(1.1)
Other Income		0.3
Allowance for Equity Funds Used During Construction		(2.5)
Non-Service Cost Components of Net Periodic Pension Cost		(0.1)
Interest Expense		(5.5)
Total Change in Expenses and Other		(35.5)
Income Tax Expense		(30.5)
Equity Earnings of Unconsolidated Subsidiary		0.1
Net Income Attributable to Noncontrolling Interests		0.2
First Quarter of 2020	$	245.3

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

- **Retail Margins** increased $6 million primarily due to the following:
  - A $25 million increase related to fuel at APCo and I&M, primarily due to the timing of recoverable PJM expenses. This increase was partially offset in other expense items below.
  - A $14 million increase due to the impact of the 2019 WVPSC order which required APCo and WPCo to offset Excess ADIT not subject to normalization requirements against the deferred fuel under-recovery balance in 2019.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $14 million increase from rate proceedings at I&M. This increase was partially offset in other expense items below.
    - An $11 million increase at PSO due to new base rates implemented in April 2019.
    - An $11 million increase at SWEPCo primarily due to capital investment rider and base rate revenue increases in Texas, Arkansas and Louisiana.
    - An $11 million increase at APCo and WPCo due to a base rate increase in West Virginia that was partially offset in Depreciation and Amortization expenses below.
    - A $5 million increase at APCo and WPCo due to revenue primarily from rate riders in West Virginia.
  - A $9 million increase due to customer refunds related to the 2018 Tax Reform. This increase was partially offset in Income Tax Expense (Benefit) below.

  These increases were partially offset by:
  - A $61 million decrease in weather-related usage primarily in the eastern region and primarily in the residential class.

- A $28 million decrease in weather-normalized retail margins primarily in the eastern region and primarily in the commercial and industrial classes.
- A $7 million decrease in revenue from rate riders at PSO. This decrease was partially offset in other expense items below.

- **Margins from Off-system Sales** decreased $5 million primarily due to WPCo's historical merchant portion of Mitchell Plant moving to base rates beginning January 2020 and weaker market prices for energy in the RTOs which caused a significant decrease in sales volume.
- **Transmission Revenues** increased $6 million primarily due to an increase in SPP transmission services revenue at SWEPCo.

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

- **Other Operation and Maintenance** expenses increased $1 million primarily due to the following:
  - An $11 million increase due to PJM transmission services including the annual formula rate true-up.
  - A $5 million increase due to SPP transmission services including the annual formula rate true-up.
  - A $3 million increase due to North Central Wind Energy Facilities expenses for SWEPCo and PSO.

  These increases were partially offset by:
  - An $11 million decrease in employee-related expenses.
  - A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2020.
- **Depreciation and Amortization** expenses increased $25 million primarily due to a higher depreciable base and increased depreciation rates approved at APCo, I&M and SWEPCo. This increase was partially offset in Retail Margins above.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances at APCo.
- **Income Tax Expense** increased $31 million primarily due to a decrease in amortization of Excess ADIT. The decrease in amortization of excess ADIT is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended March 31, 2020	2019
	(in millions)	
Revenues	$ 1,106.9	$ 1,222.0
Purchased Electricity	191.4	229.7
Amortization of Generation Deferrals	—	32.4
Gross Margin	915.5	959.9
Other Operation and Maintenance	367.2	405.9
Depreciation and Amortization	214.5	183.7
Taxes Other Than Income Taxes	146.2	145.5
Operating Income	187.6	224.8
Interest and Investment Income	0.7	1.3
Carrying Costs Income	0.4	0.2
Allowance for Equity Funds Used During Construction	7.0	6.9
Non-Service Cost Components of Net Periodic Benefit Cost	7.3	7.6
Interest Expense	(71.4)	(62.0)
Income Before Income Tax Expense	131.6	178.8
Income Tax Expense	15.4	22.3
Net Income	116.2	156.5
Net Income Attributable to Noncontrolling Interests	—	—
Earnings Attributable to AEP Common Shareholders	$ 116.2	$ 156.5

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	6,300	6,547
Commercial	5,873	5,618
Industrial	5,908	5,771
Miscellaneous	182	176
Total Retail (a)	18,263	18,112
Wholesale (b)	390	638
Total KWhs	18,653	18,750

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

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

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

	Three Months Ended March 31,	
	2020	**2019**
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,473	1,892
Normal – Heating (b)	1,898	1,877
Actual – Cooling (c)	3	1
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	91	177
Normal – Heating (b)	185	187
Actual – Cooling (d)	231	122
Normal – Cooling (b)	125	123

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 70 degree temperature base.

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

First Quarter of 2019	$	156.5
Changes in Gross Margin:		
Retail Margins		(74.2)
Margins from Off-system Sales		0.7
Transmission Revenues		11.9
Other Revenues		17.2
Total Change in Gross Margin		(44.4)
Changes in Expenses and Other:		
Other Operation and Maintenance		38.7
Depreciation and Amortization		(30.8)
Taxes Other Than Income Taxes		(0.7)
Interest and Investment Income		(0.6)
Carrying Costs Income		0.2
Allowance for Equity Funds Used During Construction		0.1
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(9.4)
Total Change in Expenses and Other		(2.8)
Income Tax Expense		6.9
First Quarter of 2020	$	116.2

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

- **Retail Margins** decreased $74 million primarily due to the following:
  - A $58 million decrease due to a reversal of a regulatory provision in Ohio in the first quarter of 2019.
  - A $39 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 $13 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 $7 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $5 million decrease due to the OVEC PPA Rider which was replaced by the Legacy Generation Resource Rider (LGRR). This decrease was offset in Margins from Off-system Sales and Other Revenues below.
  - A $4 million decrease in weather-related usage in Texas primarily due to a 49% decrease in heating degree days, partially offset by an 89% increase in cooling degree days.
  - A $3 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.

  These decreases were partially offset by:
  - A $17 million increase in rider revenues in Ohio associated with the DIR. This increase was partially offset in other expense items below.
  - A $13 million increase in weather-normalized margins primarily in the residential and commercial classes in Texas.
  - A $7 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - A $7 million increase in revenues in Ohio associated with the Universal Service Fund (USF). This increase was offset in Other Operation and Maintenance expenses below.

- A $7 million increase in revenues primarily due to the Transmission Cost Recovery Factor revenue rider in Texas.
- A $3 million increase in Ohio Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

- **Transmission Revenues** increased $12 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $17 million primarily due to the following:
  - A $12 million increase primarily due to securitization revenue in Texas. This increase was offset below in Depreciation and Amortization expenses and in Interest Expense.
  - A $4 million increase due to third-party LGRR revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses decreased $39 million primarily due to the following:

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **March 31, 2020**
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Trading Symbol	Name of Each Exchange on Which Registered
American Electric Power Company Inc	Common Stock, $6 50 par value	AEP	New York Stock Exchange
American Electric Power Company Inc	6 125% Corporate Units	AEP PR B	New York Stock Exchange

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days

Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232 405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit such files)

Yes ☒ No ☐

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

Large Accelerated filer	☒	Accelerated filer	☐	Non-accelerated filer	☐
Smaller reporting company	☐	Emerging growth company	☐		

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

Large Accelerated filer	☐	Accelerated filer	☐	Non-accelerated filer	☒
Smaller reporting company	☐	Emerging growth company	☐		

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

☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act) Yes ☐ No ☒

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

	Number of shares of common stock outstanding of the Registrants as of May 6, 2020
American Electric Power Company, Inc.	495,583,133
	($6.50 par value)
AEP Texas Inc.	*100*
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

(a) 100% interest is held by AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of American Electric Power Company, Inc.
NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
March 31, 2020

Part II. OTHER INFORMATION

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
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.
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 Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AMI	Advanced Metering Infrastructure.
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 VIE 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 rate-making purposes.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
Cardinal Operating Company	A jointly-owned organization between AGR and a nonaffiliate. The nonaffiliate operates the three unit Cardinal Plant and wholly-owns Units 2 and 3.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.
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 VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.

Term	Meaning
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE 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.
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 Fuel Adjustment Clause Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
MISO	Midcontinent Independent 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.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.

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Term	Meaning
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated VIE 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.
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.
PATH-WV	PATH West Virginia Transmission Company, LLC, a joint venture owned 50% by FirstEnergy and 50% by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
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.
Reference Rate Reform	The global transition away from referencing the London Interbank Offered Rate and other interbank offered rates, and toward new reference rates that are more reliable and robust.
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.
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.
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 VIE 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 302.4 MW wind generation facility in west Texas in which AEP owns a 75% interest.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.

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Term	Meaning
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated VIEs formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The project included the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2019 Annual Report, 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.
- The impact of pandemics, including COVID-19, and any associated disruption of AEP's business operations due to impacts on economic or market conditions, electricity usage, employees, customers, service providers, vendors and suppliers.
- 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. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2019 Annual Report and in Part II of this report.

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

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

EXECUTIVE OVERVIEW

COVID-19

In March 2020, COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. Its rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions significantly disrupted economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. As of March 31, 2020, the reduction in the demand for energy did not materially impact the Registrants' financial statements. However, if the severity of the economic disruptions increase as the duration of the COVID-19 pandemic continues, the negative financial impact due to reduced demand could be significantly greater in future periods than in the first quarter.

AEP's electric utility operating companies informed both retail customers and state regulators that disconnections for non-payment have been temporarily suspended. These uncertain economic conditions may result in the inability of customers to pay for electric service, which could affect the collectability of the Registrants' revenues and adversely affect financial results. The Registrants are evaluating and working with their state regulatory commissions on potential rate recovery mechanisms for increased costs incurred due to COVID-19. Certain Registrants received orders approving the deferral of certain incremental expenses associated with COVID-19. See Note 4 - Rate Matters for additional information. The Registrants have not observed a material change in their typical collections experience and thus did not materially adjust their allowances for uncollectible accounts as of March 31, 2020.

The effects of the continued outbreak of COVID-19 and related government responses could also include extended disruptions to supply chains and capital markets, reduced labor availability and a prolonged reduction in economic activity. These effects could have a variety of adverse impacts to the Registrants, including their ability to operate their facilities. As of March 31, 2020, there were no material adverse impacts to the Registrants' operations due to COVID-19.

In addition, the economic disruptions caused by COVID-19 could also adversely impact the impairment risks for certain long-lived assets, equity method investments and goodwill. AEP evaluated these impairment considerations and determined that no such impairments occurred as of March 31, 2020.

During the first quarter of 2020, AEP increased its liquidity position to mitigate the risk of market volatility due to COVID-19. The Registrants' access to funding was limited for a period of time during the first quarter and therefore AEP entered into a 364-day term loan to reduce reliance on commercial paper and help mitigate potential future liquidity risks. Specifically, for the first three months of 2020, AEP issued approximately $1.4 billion in long-term debt and $1.6 billion in short-term debt primarily via a 364-day term loan to enhance the Registrants' available liquidity. As of March 31, 2020, AEP's available liquidity is $2.8 billion. Management believes the Registrants have adequate liquidity under existing credit facilities. To the extent that future access to the capital markets or the cost of funding is adversely affected by COVID-19, the Registrants may need to consider alternative sources of funding for operations and working capital, which may adversely impact future results of operations, financial condition, and cash flows.

The effects of an extended disruption to the supply chains could disrupt or delay construction, testing, supervisory and support activities at renewable generation facilities, in particular, the North Central Wind Energy Facilities and the AEP Generation & Marketing segment's Flat Ridge 3 wind project. The in-service dates for the North Central Wind Energy Facilities are scheduled for end of year 2020 for one project, and end of year 2021 for the remaining two projects. Under the terms of the Purchase and Sales Agreement, PSO and SWEPCo do not have an obligation to acquire the North Central Wind Energy Facility projects if the projects are not completed by the required in-service dates. The in-service date for the Flat Ridge 3 wind project is scheduled for end of the year 2020. As of March 31, 2020, there has been no material adverse impacts to either the North Central Wind Energy Facility or the Flat Ridge 3 project. AEP currently expects the construction projects to be delivered on-time in accordance with the agreements with the developers. However, depending on the longevity and ultimate impact of COVID-19, future delays in the construction of AEP's renewable assets could occur which could impact the current construction schedule, budget, and the qualification for federal PTC. AEP is working with industry groups on potential legislative and administrative relief for a PTC continuity safe harbor extension due to the ongoing impacts of COVID-19.

In March 2020, President Trump signed into law legislation referred to as the "Coronavirus Aid, Relief, and Economic Security Act" (the CARES Act). The CARES Act includes tax relief provisions such as: (a) an Alternative Minimum Tax (AMT) Credit Refund, (b) a 5-year net operating losses (NOL) carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. As of March 31, 2020, AEP has a $20 million AMT credit refund recognized in anticipation of a refund from the U.S. Treasury. Management is evaluating the ability to recover taxes paid in 2014 under the 5-year NOL carryback provision. The Registrants currently expect to defer payments of the employer share of payroll taxes for the period March 27, 2020 through December 31, 2020 and pay 50% of the obligation by December 31, 2021 and the remaining 50% by December 31, 2022.

The Registrants are taking steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19. The Registrants have updated and implemented a company-wide pandemic plan to address specific aspects of the COVID-19. This plan guides emergency response, business continuity, and the precautionary measures AEP is taking on behalf of its employees and the public. The Registrants have taken extra precautions for employees who work in the field and for employees who work in their facilities, and have implemented work from home policies where appropriate. The Registrants will continue to monitor developments affecting both their workforce and customers, and will take additional precautions that management determines are necessary in order to mitigate the impacts. AEP continues to focus on providing safe, uninterrupted service to its customers, which includes the implementation of strong physical and cyber-security measures to ensure that its systems remain functional with a partially remote workforce. As of March 31, 2020, there has been no material adverse impact to the Registrants' business operations and customer service due to remote work. Management will continue to review and modify plans as conditions change. Despite efforts to manage these impacts to the Registrants, the ultimate impact of COVID-19 also depends on factors beyond management's knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, management cannot estimate the potential future impact to financial position, results of operations and cash flows, but the impacts could be material.

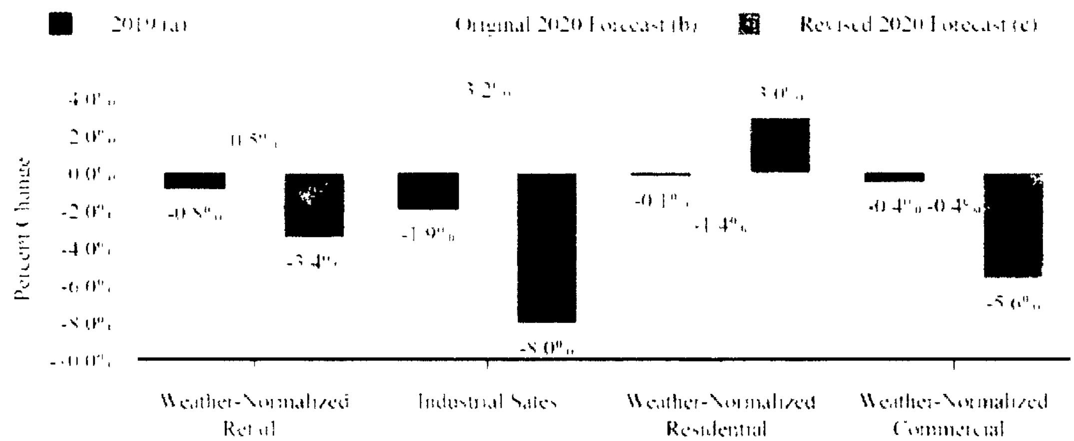
Customer Demand

AEP's weather-normalized retail sales volumes for the first quarter of 2020 decreased by 0.7% from the first quarter of 2019. AEP's first quarter 2020 industrial sales volumes decreased by 0.7% compared to the first quarter of 2019. The decline in industrial sales was spread across many industries. Weather-normalized residential sales decreased 1.2% while weather-normalized commercial sales were flat in the first quarter of 2020, from the first quarter of 2019.

Many businesses were forced to limit or reduce their operations in response to the COVID-19 outbreak over the last two weeks of the first quarter of 2020. While there is uncertainty regarding the duration and total impact that COVID-19 will have on AEP's retail sales in 2020, AEP expects COVID-19 to have a larger impact in the second quarter of 2020 than it had in the first quarter.

As a result of the impact of COVID-19, AEP revised its forecast for 2020 weather-normalized retail sales volumes from the forecast presented in the 2019 10-K. In 2020, AEP currently anticipates weather-normalized retail sales volumes will decrease by 3.4%. AEP expects industrial class sales volumes to decrease by 8% in 2020, while weather-normalized residential sales volumes are projected to increase by 3%. Finally, AEP currently projects weather-normalized commercial sales volumes to decrease by 5.6%.

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) As presented in the 2019 AEP 10-K. Forecasted percentage change for the year ended December 31, 2020 compared to the year ended December 31, 2019
(c) Revised for the impact of COVID-19. 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 Indiana Base Rate Case* - In May 2019, I&M filed a request with the IURC for a $172 million annual increase based upon a proposed 10.5% return on common equity. In March 2020, the IURC issued an order authorizing a $77 million annual base rate increase based upon a return on common equity of 9.7% effective March 2020. This increase will be phased in through January 2021 with an approximate $44 million annual increase in base rates effective March 2020 and the full $77 million annual increase effective January 2021. The order rejected I&M's proposed re-allocation of capacity costs related to the loss of a significant FERC wholesale contract, which will negatively impact I&M's annual pretax earnings by approximately $20 million starting June 2020. The IURC also rejected I&M's proposed AMI meter rider. In March 2020, I&M filed for rehearing as a result of the IURC's ruling to reject I&M's proposed re-allocation of capacity costs. Intervenors subsequently filed objections to I&M's appeal. In April 2020, I&M filed a reply to these objections on rehearing and appealed the IURC's order.

- *2017-2019 Virginia Triennial Review* - In March 2020, APCo submitted its 2017-2019 Virginia triennial earnings review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $65 million annual increase based upon a proposed 9.9% return on common equity. 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. 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. 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.

- *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 the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court. As of March 31, 2020, 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.

- In April 2020, the Virginia Clean Economy Act was signed into law by the Virginia Governor. The law will become effective July 2020 and includes requirements for Virginia electric utilities to: (a) retire no later than 2045 all electric generating units located in Virginia that emit carbon as a by-product, (b) produce 100% of the company's power to serve Virginia customers from renewable sources by 2050 with increasing percentages of mandatory renewable energy sources each year and (c) achieve increasing annual energy efficiency savings from 2022-2025 using 2019 as the base year. This law also provides that if the Virginia SCC finds in any triennial review that revenue reductions related to energy efficiency programs approved and deployed since the utility's previous triennial review have caused the utility to earn more than 70 basis points below its authorized rate of return, the Virginia SCC shall order increases to the utility's rates necessary to recover such revenue reductions. If any of these costs are not recoverable, 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 2020. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (Decrease)		Approved ROE	New Rates Effective
		(in millions)			
I&M	Indiana	$ 77.4	(a)	9.7%	March 2020
AEP Texas	Texas	(40.0)	(b)	9.4%	June 2020

(a) This increase will be phased in through January 2021 with an approximate $44 million annual increase in base rates effective March 2020 and the full $77 million annual increase effective January 2021. In March 2020, I&M filed for rehearing as a result of the IURC's ruling to reject I&M's proposed re-allocation of capacity costs.
(b) In April 2020, the PUCT issued an order approving the stipulation and settlement agreement with a capital structure of 57.5% debt and 42.5% common equity effective with the first billing cycle in June 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)		
APCo	Virginia	March 2020	$ 64.9	9.9%	(a)

(a) Commission Staff/Intervenor direct testimony to be filed by August 2020.

Renewable Generation

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

Contracted Renewable Generation Facilities

AEP continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy technologies. The Generation & Marketing segment also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties.

As of March 31, 2020, subsidiaries within AEP's Generation & Marketing segment had approximately 1,423 MWs of contracted renewable generation projects in-service. In addition, as of March 31, 2020, these subsidiaries had approximately 160 MWs of renewable generation projects under construction with total estimated capital costs of $235 million related to these projects.

Regulated Renewable Generation Facilities

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; the PSO agreement was approved by the Oklahoma Commission in February 2020. In January 2020, SWEPCo reached a joint settlement agreement with the APSC, Arkansas Attorney General's office and Walmart, Inc. Hearings in the Texas proceeding took place in February 2020. In April 2020, SWEPCo reached a joint settlement agreement with Louisiana Staff, Walmart, Inc. and the Alliance for Affordable Energy. In May 2020, the Arkansas Commission approved the settlement agreement as filed, with the exception that SWEPCo use its formula rate rider to recover its costs rather than the requested rider. SWEPCo is seeking regulatory approvals by July 2020.

Hydroelectric Generation

Evaluating Sale of Hydroelectric Generation

In March 2020, management placed 10 hydroelectric generation plants under study for a potential sale. The table below shows the net book value of each plant, including CWIP and materials and supplies, before cost of removal of the plants included in the study.

Owner	Plant Name	Units	State	Net Book Value as of March 31, 2020	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
				(in millions)		
AGR	Racine	2	OH	$ 43 2	48	1982
APCo	London	3	WV	9.6	14	1935
APCo	Marmet	3	WV	11.0	14	1935
APCo	Winfield	3	WV	13.9	15	1938
I&M	Berrien Springs	12	MI	7.7	6	1908
I&M	Buchanan	10	MI	5.1	3	1919
I&M	Constantine	4	MI	2.6	1	1921
I&M	Elkhart	3	IN	5 5	3	1913
I&M	Mottville	4	MI	2.9	2	1923
I&M	Twin Branch Hydro	8	IN	7.1	5	1904
	Total			$ 108.6	111	

If management decides to proceed with the sale of these plants, FERC approval would be required. In addition, for all plants, except for Racine, state commission approval would be required. Management currently estimates that any potential sale of these plants would not be completed until late 2020 at the earliest. There is no assurance that management will be able to sell any of these plants.

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. DHLC provides 100% of the fuel supply to Dolet Hills Power Station. In March 2020, it was determined that DHLC would not proceed developing additional mining areas for future lignite extraction and management notified a substantial portion of its workforce that employment will permanently end in June 2020. Based on these actions, management has revised the estimated useful life of many of DHLC's assets to June 2020 to coincide with the date at which extraction is expected to be discontinued. Management also revised the useful life of the Dolet Hills Power Station to September 2021 based on the remaining estimated fuel supply available for continued seasonal operation. In March 2020, primarily due to the revision in the useful life of DHLC, SWEPCo recorded a revision to increase estimated ARO liabilities by $21 million. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the pending cessation of lignite mining in June 2020.

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 $151 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 March 31, 2020, DHLC has unbilled lignite inventory and fixed costs of $124 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 March 31, 2020, Oxbow has unbilled fixed costs of $26 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.

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. In March 2020, as a follow-up to its 2019 Notice of Inquiry regarding transmission incentives policy, FERC issued a Notice of Proposed Rulemaking and requested comments by July 2020. AEP will file comments and monitor this proceeding. 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 5 – 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 the denial to those claims have been appealed to the AEP System Retirement Plan Appeal Committee. 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 March 31, 2020, 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 March 31, 2020.

Company	Plant Name and Unit	Generating Capacity		Amounts Pending Regulatory Approval
		(in MWs)		(in millions)
APCo (a)	Kanawha River Plant	400	$	14.0
APCo (b)	Clinch River Plant	705		25 3
APCo (a)	Sporn Plant, Units 1 and 3	300		2.0
APCo (a)	Glen Lyn Plant	335		3 4
SWEPCo (c)	Welsh Plant, Unit 2	528		35.5
Total		2,268	$	80.2

(a) Remaining amounts pending regulatory approval represent the FERC and the West Virginia jurisdictional share
(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

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 (SCR) 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 (DSI) 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.

In April 2020, an employee at the Rockport Plant was diagnosed with COVID-19. Several contract workers stopped working on the SCR project at Rockport Unit 2, and the project workforce reported an increased rate of absenteeism. I&M has notified the parties to the consent decree of this force majeure event and estimates that the date for completion of the SCR and DSI projects will be extended by approximately two weeks past the June 1, 2020 deadline. Management will continue to oversee the project through completion in light of these challenges.

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. A proposed rule to retain the existing PM standards was released in April 2020. 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 certain 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. In April 2020, the Federal EPA released a final rule adopting the conclusions set forth in the proposal and retaining the existing MATS standards.

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. In April 2020, Virginia enacted clean energy legislation to allow the state to participate in the Regional Greenhouse Gas Initiative, require the retirement of all fossil-fueled generation by 2045 and require 100% renewable energy to be provided to Virginia customers by 2050. 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. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit based on its determination that discharges from an injection well that make their way to the Pacific Ocean through ground water may require a permit if the distance traveled through ground water, length of time to reach the surface water and other factors make it "functionally equivalent" to a direct discharge from a point source. The second case was also remanded to the lower court. Prior to the Supreme Court's decision, 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 these developments 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 March 2020, Virginia's Governor signed House Bill 443 (HB 443) requiring APCo to close ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. APCo's current ARO for these units is based on closure in place and will require future revision to reflect the costs of closure by removal. As of March 31, 2020, APCo is unable to reasonably estimate this cost. Management expects to record a material revision to the ARO after engineering plans for the removal are developed later in 2020. The closure is required to be completed within 15 years from the start of the excavation process. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause (E-RAC). APCo may begin deferring incurred costs on July 1, 2020 and recovering these costs through the E-RAC beginning July 1, 2022. APCo is permitted to record carrying costs on the unrecovered balance of closure costs at a weighted average cost of capital approved by the Virginia SCC. HB 443 also allows any closure costs allocated to non-Virginia jurisdictional customers, but not collected from such non-Virginia jurisdictional customers, to be recovered from Virginia jurisdictional customers through the E-RAC. Management does not expect HB 443 to materially impact results of operations or cash flows, but does anticipate a material impact to APCo's balance sheet.

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 participate in rulemaking activities and make adjustments based on new federal and state requirements affecting its ash disposal units.

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. The final replacement rule was published in the Federal Register in April 2020 and will become effective in June 2020. The final rule limits the scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, artificial ponds and waste treatment systems.

In April 2020, the U.S. District Court for the District of Montana issued a decision vacating the U.S. Army Corps of Engineers' (Corps) General Nationwide Permit 12 (NWP 12), which provides standard conditions governing linear utility projects in streams, wetlands and other waters of the United States having minimal adverse environmental impacts. The Court found that in reissuing NWP 12 in 2017, the Corps failed to comply with Section 7 of the Endangered Species Act (ESA), which requires the Corps to consult with the U.S. Fish and Wildlife Service regarding potential impacts on endangered species. The Court remanded the permit back to the Corps to complete its ESA consultation, and also enjoined the Corps from authorizing any dredge or fill activities under NWP 12 pending completion of the consultation process. The Department of Justice filed a motion to stay the injunction and tailor the remedy imposed by the Court, and the court ordered the parties to file briefs on the issue in May 2020. Management is monitoring the litigation and evaluating other permitting alternatives, but is currently unable to predict the impact of this decision on current and planned projects.

RESULTS OF OPERATIONS

SEGMENTS

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

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

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

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

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019
	(in millions)	
Vertically Integrated Utilities	$ 245.3	$ 302.4
Transmission and Distribution Utilities	116.2	156.5
AEP Transmission Holdco	140.6	124.2
Generation & Marketing	28.4	40.1
Corporate and Other	(35.3)	(50.4)
Earnings Attributable to AEP Common Shareholders	$ 495.2	$ 572.8

AEP CONSOLIDATED

First Quarter of 2020 Compared to First Quarter of 2019

Earnings Attributable to AEP Common Shareholders decreased from $573 million in 2019 to $495 million in 2020 to primarily due to:

- A decrease in weather-related usage.
- A one-time reversal of a regulatory provision in 2019.

These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended March 31, 2020	2019
	(in millions)	
Revenues	$ 2,226.7	$ 2,403.3
Fuel and Purchased Electricity	671.2	856.4
Gross Margin	1,555.5	1,546.9
Other Operation and Maintenance	691.3	690.1
Depreciation and Amortization	381.7	356.3
Taxes Other Than Income Taxes	117.1	116.0
Operating Income	365.4	384.5
Other Income	1.6	1.3
Allowance for Equity Funds Used During Construction	8.2	10.7
Non-Service Cost Components of Net Periodic Benefit Cost	16.9	17.0
Interest Expense	(144.5)	(139.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings	247.6	274.5
Income Tax Expense (Benefit)	2.1	(28.4)
Equity Earnings of Unconsolidated Subsidiary	0.8	0.7
Net Income	246.3	303.6
Net Income Attributable to Noncontrolling Interests	1.0	1.2
Earnings Attributable to AEP Common Shareholders	$ 245.3	$ 302.4

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	8,262	9,216
Commercial	5,366	5,633
Industrial	8,475	8,545
Miscellaneous	530	546
Total Retail	22,633	23,940
Wholesale (a)	3,618	5,804
Total KWhs	26,251	29,744

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended March 31,	
	2020	**2019**
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,241	1,571
Normal – Heating (b)	1,611	1,595
Actual – Cooling (c)	13	1
Normal – Cooling (b)	5	5
Western Region		
Actual – Heating (a)	649	941
Normal – Heating (b)	867	866
Actual – Cooling (c)	51	11
Normal – Cooling (b)	28	28

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

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

First Quarter of 2019	$	302.4
Changes in Gross Margin:		
Retail Margins		5.9
Margins from Off-system Sales		(5.2)
Transmission Revenues		6.1
Other Revenues		1.8
Total Change in Gross Margin		8.6
Changes in Expenses and Other:		
Other Operation and Maintenance		(1.2)
Depreciation and Amortization		(25.4)
Taxes Other Than Income Taxes		(1.1)
Other Income		0.3
Allowance for Equity Funds Used During Construction		(2.5)
Non-Service Cost Components of Net Periodic Pension Cost		(0.1)
Interest Expense		(5.5)
Total Change in Expenses and Other		(35.5)
Income Tax Expense		(30.5)
Equity Earnings of Unconsolidated Subsidiary		0.1
Net Income Attributable to Noncontrolling Interests		0.2
First Quarter of 2020	$	245.3

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

- **Retail Margins** increased $6 million primarily due to the following:
  - A $25 million increase related to fuel at APCo and I&M, primarily due to the timing of recoverable PJM expenses. This increase was partially offset in other expense items below.
  - A $14 million increase due to the impact of the 2019 WVPSC order which required APCo and WPCo to offset Excess ADIT not subject to normalization requirements against the deferred fuel under-recovery balance in 2019.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $14 million increase from rate proceedings at I&M. This increase was partially offset in other expense items below.
    - An $11 million increase at PSO due to new base rates implemented in April 2019.
    - An $11 million increase at SWEPCo primarily due to capital investment rider and base rate revenue increases in Texas, Arkansas and Louisiana.
    - An $11 million increase at APCo and WPCo due to a base rate increase in West Virginia that was partially offset in Depreciation and Amortization expenses below.
    - A $5 million increase at APCo and WPCo due to revenue primarily from rate riders in West Virginia.
  - A $9 million increase due to customer refunds related to the 2018 Tax Reform. This increase was partially offset in Income Tax Expense (Benefit) below.

  These increases were partially offset by:
  - A $61 million decrease in weather-related usage primarily in the eastern region and primarily in the residential class.

  - A \$28 million decrease in weather-normalized retail margins primarily in the eastern region and primarily in the commercial and industrial classes.
  - A \$7 million decrease in revenue from rate riders at PSO. This decrease was partially offset in other expense items below.
- **Margins from Off-system Sales** decreased \$5 million primarily due to WPCo's historical merchant portion of Mitchell Plant moving to base rates beginning January 2020 and weaker market prices for energy in the RTOs which caused a significant decrease in sales volume.
- **Transmission Revenues** increased \$6 million primarily due to an increase in SPP transmission services revenue at SWEPCo.

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

- **Other Operation and Maintenance** expenses increased \$1 million primarily due to the following:
  - An \$11 million increase due to PJM transmission services including the annual formula rate true-up.
  - A \$5 million increase due to SPP transmission services including the annual formula rate true-up.
  - A \$3 million increase due to North Central Wind Energy Facilities expenses for SWEPCo and PSO.

  These increases were partially offset by:
  - An \$11 million decrease in employee-related expenses.
  - A \$7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2020.
- **Depreciation and Amortization** expenses increased \$25 million primarily due to a higher depreciable base and increased depreciation rates approved at APCo, I&M and SWEPCo. This increase was partially offset in Retail Margins above.
- **Interest Expense** increased \$6 million primarily due to higher long-term debt balances at APCo.
- **Income Tax Expense** increased \$31 million primarily due to a decrease in amortization of Excess ADIT. The decrease in amortization of excess ADIT is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended March 31, 2020	2019
	(in millions)	
Revenues	$ 1,106.9	$ 1,222.0
Purchased Electricity	191.4	229.7
Amortization of Generation Deferrals	—	32.4
Gross Margin	915.5	959.9
Other Operation and Maintenance	367.2	405.9
Depreciation and Amortization	214.5	183.7
Taxes Other Than Income Taxes	146.2	145.5
Operating Income	187.6	224.8
Interest and Investment Income	0.7	1.3
Carrying Costs Income	0.4	0.2
Allowance for Equity Funds Used During Construction	7.0	6.9
Non-Service Cost Components of Net Periodic Benefit Cost	7.3	7.6
Interest Expense	(71.4)	(62.0)
Income Before Income Tax Expense	131.6	178.8
Income Tax Expense	15.4	22.3
Net Income	116.2	156.5
Net Income Attributable to Noncontrolling Interests	—	—
Earnings Attributable to AEP Common Shareholders	$ 116.2	$ 156.5

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2020	2019
	(in millions of KWhs)	
Retail:		
Residential	6,300	6,547
Commercial	5,873	5,618
Industrial	5,908	5,771
Miscellaneous	182	176
Total Retail (a)	18,263	18,112
Wholesale (b)	390	638
Total KWhs	18,653	18,750

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

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

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

	Three Months Ended March 31,	
	2020	**2019**
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,473	1,892
Normal – Heating (b)	1,898	1,877
Actual – Cooling (c)	3	1
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	91	177
Normal – Heating (b)	185	187
Actual – Cooling (d)	231	122
Normal – Cooling (b)	125	123

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 70 degree temperature base.

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

First Quarter of 2019	$	156.5
Changes in Gross Margin:		
Retail Margins		(74.2)
Margins from Off-system Sales		0.7
Transmission Revenues		11.9
Other Revenues		17.2
Total Change in Gross Margin		(44.4)
Changes in Expenses and Other:		
Other Operation and Maintenance		38.7
Depreciation and Amortization		(30.8)
Taxes Other Than Income Taxes		(0.7)
Interest and Investment Income		(0.6)
Carrying Costs Income		0.2
Allowance for Equity Funds Used During Construction		0.1
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(9.4)
Total Change in Expenses and Other		(2.8)
Income Tax Expense		6.9
First Quarter of 2020	$	116.2

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

- **Retail Margins** decreased $74 million primarily due to the following:
  - A $58 million decrease due to a reversal of a regulatory provision in Ohio in the first quarter of 2019.
  - A $39 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 $13 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 $7 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $5 million decrease due to the OVEC PPA Rider which was replaced by the Legacy Generation Resource Rider (LGRR). This decrease was offset in Margins from Off-system Sales and Other Revenues below.
  - A $4 million decrease in weather-related usage in Texas primarily due to a 49% decrease in heating degree days, partially offset by an 89% increase in cooling degree days.
  - A $3 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.

  These decreases were partially offset by:
  - A $17 million increase in rider revenues in Ohio associated with the DIR. This increase was partially offset in other expense items below.
  - A $13 million increase in weather-normalized margins primarily in the residential and commercial classes in Texas.
  - A $7 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - A $7 million increase in revenues in Ohio associated with the Universal Service Fund (USF). This increase was offset in Other Operation and Maintenance expenses below.

- A $7 million increase in revenues primarily due to the Transmission Cost Recovery Factor revenue rider in Texas.
- A $3 million increase in Ohio Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

- **Transmission Revenues** increased $12 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $17 million primarily due to the following:
  - A $12 million increase primarily due to securitization revenue in Texas. This increase was offset below in Depreciation and Amortization expenses and in Interest Expense.
  - A $4 million increase due to third-party LGRR revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses decreased $39 million primarily due to the following:
  - A $40 million decrease in PJM expenses that were fully recovered in rate riders/trackers in Gross Margin above.
  - A $6 million decrease in PJM expenses primarily related to the annual formula rate true-up.

  These decreases were partially offset by:
  - An $8 million increase in distribution-related expenses.
  - A $7 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $31 million primarily due to the following:
  - A $15 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $12 million increase in securitization amortizations in Texas. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $5 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 $5 million increase in Ohio recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.

  These increases were partially offset by:
  - A $10 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.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $7 million due to a decrease in pretax book income, partially offset by a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset in Retail Margins above.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended March 31, 2020	2019
	(in millions)	
Transmission Revenues	$ 310.2	$ 256.4
Other Operation and Maintenance	29.9	22.3
Depreciation and Amortization	58.1	41.8
Taxes Other Than Income Taxes	51.9	42.6
Operating Income	170.3	149.7
Interest and Investment Income	0.9	0.7
Allowance for Equity Funds Used During Construction	16.2	11.3
Non-Service Cost Components of Net Periodic Benefit Cost	0.5	0.6
Interest Expense	(30.8)	(23.0)
Income Before Income Tax Expense and Equity Earnings	157.1	139.3
Income Tax Expense	38.4	31.9
Equity Earnings of Unconsolidated Subsidiary	22.9	17.8
Net Income	141.6	125.2
Net Income Attributable to Noncontrolling Interests	1.0	1.0
Earnings Attributable to AEP Common Shareholders	$ 140.6	$ 124.2

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	As of March 31, 2020	2019
	(in millions)	
Plant in Service	$ 9,086.6	$ 7,073.6
Construction Work in Progress	1,576.3	1,899.6
Accumulated Depreciation and Amortization	464.0	318.8
Total Transmission Property, Net	$ 10,198.9	$ 8,654.4

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

First Quarter of 2019	$	124 2
Changes in Transmission Revenues:		
Transmission Revenues		53 8
Total Change in Transmission Revenues		53.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(7.6)
Depreciation and Amortization		(16.3)
Taxes Other Than Income Taxes		(9.3)
Other Income		0.2
Allowance for Equity Funds Used During Construction		4.9
Non-Service Cost Components of Net Periodic Pension Cost		(0.1)
Interest Expense		(7.8)
Total Change in Expenses and Other		(36.0)
Income Tax Expense		(6.5)
Equity Earnings of Unconsolidated Subsidiary		5.1
First Quarter of 2020	$	140.6

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

- **Transmission Revenues** increased $54 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $8 million primarily due to the following:
  - A $3 million increase due to employee-related expenses.
  - A $2 million increase due to higher rent expense.
  - A $2 million increase due to continued investment in transmission assets.
- **Depreciation and Amortization** expenses increased $16 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $5 million primarily due to the following:
  - A $9 million increase due to prior year FERC audit findings.

  This increase was partially offset by:
  - A $5 million decrease due to a decrease in CWIP.
- **Interest Expense** increased $8 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $7 million primarily due to higher pretax book income.
- **Equity Earnings of Unconsolidated Subsidiary** increased $5 million primarily due to higher pretax equity earnings at PATH-WV.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended March 31, 2020	2019
	(in millions)	
Revenues	$ 438.6	$ 481.8
Fuel, Purchased Electricity and Other	360.3	383.3
Gross Margin	**78.3**	**98.5**
Other Operation and Maintenance	41.4	50.6
Depreciation and Amortization	17.7	12.9
Taxes Other Than Income Taxes	3.4	3.8
Operating Income	**15.8**	31.2
Interest and Investment Income	1.0	2.3
Non-Service Cost Components of Net Periodic Benefit Cost	3.9	3.7
Interest Expense	(8.5)	(3.8)
Income Before Income Tax Benefit and Equity Earnings	12.2	33.4
Income Tax Benefit	(12.4)	(5.8)
Equity Earnings of Unconsolidated Subsidiaries	5.9	—
Net Income	30.5	39.2
Net Earnings (Loss) Attributable to Noncontrolling Interests	2.1	(0.9)
Earnings Attributable to AEP Common Shareholders	$ 28.4	$ 40.1

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended March 31, 2020	2019
	(in millions of MWhs)	
Fuel Type:		
Coal	1	1
Renewables	1	—
Total MWhs	2	1

First Quarter of 2020 Compared to First Quarter of 2019

Reconciliation of First Quarter of 2019 to First Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

First Quarter of 2019	$	40.1
Changes in Gross Margin:		
Merchant Generation		(37.4)
Renewable Generation		13.3
Retail, Trading and Marketing		3.9
Total Change in Gross Margin		(20.2)
Changes in Expenses and Other:		
Other Operation and Maintenance		9.2
Depreciation and Amortization		(4.8)
Taxes Other Than Income Taxes		0.4
Interest and Investment Income		(1.3)
Non-Service Cost Components of Net Periodic Benefit Cost		0.2
Interest Expense		(4.7)
Total Change in Expenses and Other		(1.0)
Income Tax Benefit		6.6
Equity Earnings of Unconsolidated Subsidiaries		5.9
Net Earnings (Loss) Attributable to Noncontrolling Interests		(3.0)
First Quarter of 2020	$	28.4

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

- **Merchant Generation** decreased $37 million primarily due to lower energy margins in 2020 and a reduction in revenues related to the retirement of Conesville Units 5 and 6 in 2019.
- **Renewable Generation** increased $13 million primarily due to the acquisition of Sempra Renewables LLC and new projects placed in-service.
- **Retail, Trading and Marketing** increased $4 million due to higher retail margins partially offset by lower trading and marketing activity.

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

- **Other Operation and Maintenance** expenses decreased $9 million primarily due to the retirement of Conesville Units 5 and 6 in 2019 partially offset by expenses related to increased investments in wind farms and other renewable energy sources.
- **Depreciation and Amortization** expenses increased $5 million due to a higher depreciable base from increased investments in renewable energy sources.
- **Interest Expense** increased $5 million primarily due to increased borrowing costs related to the Sempra Renewables LLC acquisition.
- **Income Tax Benefit** increased $7 million primarily due to a decrease in pretax book income and an increase in PTC.
- **Equity Earnings of Unconsolidated Subsidiaries** increased $6 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

First Quarter of 2020 Compared to First Quarter of 2019

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $50 million in 2019 to a loss of $35 million in 2020 primarily due to:

- A $22 million decrease in income tax expense due to a decrease in consolidating tax adjustments and discrete items recorded in 2019.
- A $13 million decrease in general corporate expenses.
- A $5 million write-off of an equity investment and related assets in 2019.

These items were partially offset by:

- A $14 million decrease in interest income due to a lower return on investments held by EIS.
- An $11 million increase in interest expense as a result of increased debt outstanding.

AEP SYSTEM INCOME TAXES

First Quarter of 2020 Compared to First Quarter of 2019

Income Tax Expense increased $2 million primarily due to a decrease in amortization of Excess ADIT. This increase is partially offset by a decrease in pretax book income and an increase in PTC.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	March 31, 2020		December 31, 2019	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 27,892.7	53.3%	$ 26,725.5	54.1%
Short-term Debt	4,464.1	8.5	2,838.3	5.7
Total Debt	32,356.8	61.8	29,563.8	59.8
AEP Common Equity	19,728.4	37.7	19,632.2	39.6
Noncontrolling Interests	279.3	0.5	281.0	0.6
Total Debt and Equity Capitalization	$ 52,364.5	100.0%	$ 49,477.0	100.0%

AEP's ratio of debt-to-total capital increased from 59.8% as of December 31, 2019 to 61.8% as of March 31, 2020 primarily due to an increase in short-term debt to enhance liquidity as a result of volatility in the capital markets.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of March 31, 2020, 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. There was increased volatility in the capital markets during the first quarter of 2020 resulting in higher commercial paper cost and limited access. To address these issues and the uncertainty around COVID-19, in March 2020, AEP entered into a $1 billion 364-day Term Loan and borrowed the full amount.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of March 31, 2020, available liquidity was approximately $2.8 billion as illustrated in the table below:

		Amount	Maturity
Commercial Paper Backup:		(in millions)	
Revolving Credit Facility	$	4,000.0	June 2022
364-Day Term Loan		1,000 0	March 2021
Cash and Cash Equivalents		1,554.6	
Total Liquidity Sources		6,554.6	
Less: AEP Commercial Paper Outstanding		2,709.6	
364-Day Term Loan		1,000.0	
Net Available Liquidity	$	2,845 0	

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 the first three months of 2020 was $3 billion. The weighted-average interest rate for AEP's commercial paper during 2020 was 2.06%.

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 March 31, 2020 was $241 million with maturities ranging from April 2020 to March 2021.

Securitized Accounts Receivables

AEP's 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 March 31, 2020, this contractually-defined percentage was 59.8%. 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 acquisition of Sempra Renewables LLC. See Note 12 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.70 per share in April 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 12 for additional information.

Credit Ratings

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

CASH FLOW

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

	Three Months Ended March 31,	
	2020	**2019**
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 432.6	$ 444 1
Net Cash Flows from Operating Activities	615 7	808 3
Net Cash Flows Used for Investing Activities	(1,766.0)	(1,582.8)
Net Cash Flows from Financing Activities	2,388 5	693.5
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	1,238.2	(81.0)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 1,670 8	$ 363.1

Operating Activities

	Three Months Ended March 31,			
	2020		2019	
	(in millions)			
Net Income	$	499 3	$	574.1
Non-Cash Adjustments to Net Income (a)		692 1		618 8
Mark-to-Market of Risk Management Contracts		57.4		65.5
Property Taxes		(59 8)		(75 6)
Deferred Fuel Over/Under-Recovery, Net		63.1		32.5
Recovery of Ohio Capacity Costs		—		14.7
Refund of Global Settlement		—		(4.1)
Change in Other Noncurrent Assets		(50 8)		(47 9)
Change in Other Noncurrent Liabilities		(74.8)		67.3
Change in Certain Components of Working Capital		(510 8)		(437.0)
Net Cash Flows from Operating Activities	$	615.7	$	808.3

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, AFUDC and Amortization of Nuclear Fuel

Net Cash Flows from Operating Activities decreased by $193 million primarily due to the following:

- A $142 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 $74 million decrease in cash from Change in Certain Components of Working Capital. The decrease is primarily due to timing of accounts receivable and accounts payable, an increase in employee-related payments, a decrease in current year employee-related expenses and a decrease in accrued taxes primarily due to the Alternative Minimum Tax Credit Refund recorded as a result of the Coronavirus Aid, Relief, and Economic Security Act. These decreases were partially offset by a refund from the Department of Energy for SNF and by the reversal of a regulatory provision at OPCo in the prior year.

Investing Activities

	Three Months Ended March 31,			
	2020		2019	
	(in millions)			
Construction Expenditures	$	(1,792.7)	$	(1,565.4)
Acquisitions of Nuclear Fuel		(1.3)		(32.4)
Other		28.0		15.0
Net Cash Flows Used for Investing Activities	$	(1,766 0)	$	(1,582.8)

Net Cash Flows Used for Investing Activities increased by $183 million primarily due to the following:

- A $227 million increase due to increased construction expenditures, primarily driven by increases at AEP Transmission Holdco of $120 million, Vertically Integrated Utilities of $84 million and Transmission and Distribution Utilities of $19 million.

Financing Activities

		Three Months Ended March 31,		
		2020		2019
		(in millions)		
Issuance of Common Stock	$	56.1	$	14.5
Issuance/Retirement of Debt, Net		2,744.2		1,013 0
Dividends Paid on Common Stock		(363.7)		(333.6)
Other		(48.1)		(0 4)
Net Cash Flows from Financing Activities	$	2,388.5	$	693.5

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

- A $1.7 billion increase in cash primarily due to an increase in short-term debt including the 364-day Term Loan borrowing. See Note 12 - Financing Activities for additional information.
- A $133 million increase in issuances of long-term debt. See Note 12 - Financing Activities for additional information.

This increase in cash was partially offset by:

- An $80 million decrease in cash due to increased retirements of long-term debt. See Note 12 - Financing Activities for additional information.

See "Long-term Debt Subsequent Events" section of Note 12 for Long-term debt and other securities issued, retired and principal payments made after March 31, 2020 through May 6, 2020, the date that the first quarter 10-Q was issued.

BUDGETED CAPITAL EXPENDITURES

Management currently estimates $5.8 billion of capital expenditures for 2020 and forecasts approximately $32.9 billion of capital expenditures for 2020 to 2024. 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. For complete information of forecasted capital expenditures, see the "Budgeted Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2019 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2019 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2019 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting standards.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards adopted in 2020 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, Executive Vice President of Utilities, 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 effects of COVID-19 may adversely impact AEP's risk management contracts on a forward basis. Markets could experience reduced market liquidity as they face potential uncertainties. Credit risk may increase as counterparties encounter business and supply chain disruptions and overall solvency challenges. Also, interest rates could continue to see increased volatility as capital markets confront uncertainty.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2019:

MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 31, 2020

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2019	$ 75 9	$ (103.6)	$ 163.4	$ 135.7
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(36 7)	(2 1)	(6 9)	(45 7)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	0.5	0.5
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	(7 4)	(7 4)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(29.1)	(17.3)	—	(46.4)
Total MTM Risk Management Contract Net Assets (Liabilities) as of March 31, 2020	$ 10 1	$ (123 0)	$ 149 6	36 7
Commodity Cash Flow Hedge Contracts				(159.1)
Interest Rate Cash Flow Hedge Contracts				(5.0)
Fair Value Hedge Contracts				57.0
Collateral Deposits				75 8
Total MTM Derivative Contract Net Assets as of March 31, 2020				$ 5.4

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

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

Credit Risk

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

AEP has risk management contracts (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 March 31, 2020, credit exposure net of collateral to sub investment grade counterparties was approximately 6.9%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of March 31, 2020, 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	$ 493.5	$ —	$ 493.5	2	$ 255.5
Split Rating	3.0	—	3.0	2	3.0
No External Ratings:					
Internal Investment Grade	148.8	—	148.8	3	90.7
Internal Noninvestment Grade	58.5	10.5	48.0	2	30.1
Total as of March 31, 2020	$ 703.8	$ 10.5	$ 693.3		

All exposure in the table above relates to AEPSC and AEPEP as AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries and AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of March 31, 2020, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

Three Months Ended March 31, 2020				Twelve Months Ended December 31, 2019			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.1	$ 0.3	$ 0.1	$ —	$ 0.1	$ 1.2	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Three Months Ended March 31, 2020				Twelve Months Ended December 31, 2019			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.7	$ 1.2	$ 0.6	$ 0.1	$ 0.2	$ 8.5	$ 1.1	$ 0.2

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

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

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the three months ended March 31, 2020 and 2019, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $24 million and $25 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2020 and 2019
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended March 31, 2020	2019
REVENUES		
Vertically Integrated Utilities	$ 2,193.0	$ 2,372.3
Transmission and Distribution Utilities	1,075.2	1,179.8
Generation & Marketing	408.4	439.7
Other Revenues	70.9	65.0
TOTAL REVENUES	3,747.5	4,056.8
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	355.3	550.4
Purchased Electricity for Resale	795.7	861.8
Other Operation	602.1	666.0
Maintenance	249.5	274.5
Depreciation and Amortization	672.2	605.8
Taxes Other Than Income Taxes	321.1	309.9
TOTAL EXPENSES	2,995.9	3,268.4
OPERATING INCOME	751.6	788.4
Other Income (Expense):		
Other Income (Expense)	(4.4)	8.6
Allowance for Equity Funds Used During Construction	31.4	28.9
Non-Service Cost Components of Net Periodic Benefit Cost	29.7	30.0
Interest Expense	(292.1)	(255.8)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	516.2	600.1
Income Tax Expense	46.5	44.5
Equity Earnings of Unconsolidated Subsidiaries	29.6	18.5
NET INCOME	499.3	574.1
Net Income Attributable to Noncontrolling Interests	4.1	1.3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 495.2	$ 572.8
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	494,596,869	493,309,076
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.00	$ 1.16
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	496,608,918	494,484,144
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.00	$ 1.16

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended March 31, 2020	Three Months Ended March 31, 2019
Net Income	$ 499 3	$ 574 1
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(17 8) and $(7 7) in 2020 and 2019, Respectively	(67 0)	(28 9)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0 5) and $(0 4) in 2020 and 2019, Respectively	(1 8)	(1 4)
TOTAL OTHER COMPREHENSIVE LOSS	(68 8)	(30.3)
TOTAL COMPREHENSIVE INCOME	430 5	543 8
Total Other Comprehensive Income Attributable To Noncontrolling Interests	4 1	1 3
TOTAL OTHER COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 426.4	$ 542 5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2020 and 2019
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
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 1	1 2	13 3				14 5
Common Stock Dividends				(332 5) (b)		(1 1)	(333 6)
Other Changes in Equity			(56 6) (a)			1 0	(55.6)
Net Income				572 8		1 3	574 1
Other Comprehensive Loss					(30 3)		(30 3)
TOTAL EQUITY – MARCH 31, 2019	513 6	$ 3,338 6	$ 6,442 8	$ 9,565 6	$ (150 7)	$ 32 2	$ 19,228 5
TOTAL EQUITY – DECEMBER 31, 2019	514 4	$ 3,343 4	$ 6,535 6	$ 9,900 9	$ (147 7)	$ 281 0	$ 19,913 2
Issuance of Common Stock	1 0	6 8	49 3				56 1
Common Stock Dividends				(359 1) (b)		(4 6)	(363 7)
Other Changes in Equity			(29 0)			(1 2)	(30 2)
ASU 2016-13 Adoption				1 8			1 8
Net Income				495 2		4 1	499 3
Other Comprehensive Loss					(68 8)		(68 8)
TOTAL EQUITY – MARCH 31, 2020	515 4	$ 3,350 2	$ 6,555 9	$ 10,038 8	$ (216 5)	$ 279 3	$ 20,007 7

(a) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units
(b) Cash dividends declared per AEP common share were $0 70 and $0 67 for the three months ended March 31, 2020 and 2019, respectively

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2020 and December 31, 2019
(in millions)
(Unaudited)

	March 31, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,554 6	$ 246 8
Restricted Cash (March 31, 2020 and December 31, 2019 Amounts Include $116 2 and $185 8, Respectively, Related to Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	116 2	185 8
Other Temporary Investments (March 31, 2020 and December 31, 2019 Amounts Include $163 6 and $187 8, Respectively, Related to EIS and Transource Energy)	185 2	202 7
Accounts Receivable		
Customers	617 9	625 3
Accrued Unbilled Revenues	242 2	222 4
Pledged Accounts Receivable – AEP Credit	885 2	873.9
Miscellaneous	41 1	27 2
Allowance for Uncollectible Accounts	(44.9)	(43 7)
Total Accounts Receivable	1,741 5	1,705 1
Fuel	550.9	528 5
Materials and Supplies	645 0	640 7
Risk Management Assets	130 4	172 8
Regulatory Asset for Under-Recovered Fuel Costs	80 8	92 9
Margin Deposits	68 3	60 4
Prepayments and Other Current Assets	219 1	242 1
TOTAL CURRENT ASSETS	5,292 0	4,077 8
PROPERTY, PLANT AND EQUIPMENT		
Electric		
Generation	22,853 7	22,762 4
Transmission	25,314 2	24,808 6
Distribution	22,824 4	22,443 4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,913 2	4,811 5
Construction Work in Progress	4,511 5	4,319 8
Total Property, Plant and Equipment	80,417 0	79,145 7
Accumulated Depreciation and Amortization	19,368 1	19,007.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	61,048 9	60,138 1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,197 4	3,158.8
Securitized Assets	789 1	858 1
Spent Nuclear Fuel and Decommissioning Trusts	2,679 2	2,975.7
Goodwill	52 5	52 5
Long-term Risk Management Assets	323 7	266 6
Operating Lease Assets	926 7	957 4
Deferred Charges and Other Noncurrent Assets	3,414 5	3,407 3
TOTAL OTHER NONCURRENT ASSETS	11,383 1	11,676 4
TOTAL ASSETS	$ 77,724 0	$ 75,892 3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 110.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2020 and December 31, 2019
(in millions, except per-share and share amounts)
(Unaudited)

	March 31, 2020	December 31, 2019
CURRENT LIABILITIES		
Accounts Payable	$ 1,593 4	$ 2,085.8
Short-term Debt		
Securitized Debt for Receivables – AEP Credit	724 0	710 0
Other Short-term Debt	3,740 1	2,128 3
Total Short-term Debt	4,464.1	2,838 3
Long-term Debt Due Within One Year (March 31, 2020 and December 31, 2019 Amounts Include $289 6 and $565 1, Respectively, Related to Transition Funding, DCC Fuel, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)	2,109 7	1,598 7
Risk Management Liabilities	156 8	114 3
Customer Deposits	361 0	366 1
Accrued Taxes	1,255 4	1,357 8
Accrued Interest	307 9	243 6
Obligations Under Operating Leases	234.3	234 1
Regulatory Liability for Over-Recovered Fuel Costs	137 6	86 6
Other Current Liabilities	1,034 5	1,373 8
TOTAL CURRENT LIABILITIES	11,654 7	10,299 1
NONCURRENT LIABILITIES		
Long-term Debt (March 31, 2020 and December 31, 2019 Amounts Include $1,037 6 and $907, Respectively, Related to Transition Funding, DCC Fuel, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)	25,783 0	25,126 8
Long-term Risk Management Liabilities	291 9	261 8
Deferred Income Taxes	7,668 5	7,588.2
Regulatory Liabilities and Deferred Investment Tax Credits	8,049 2	8,457 6
Asset Retirement Obligations	2,254 2	2,216 6
Employee Benefits and Pension Obligations	451 0	466 0
Obligations Under Operating Leases	736.3	734 6
Deferred Credits and Other Noncurrent Liabilities	709 5	719 8
TOTAL NONCURRENT LIABILITIES	45,943 6	45,571 4
TOTAL LIABILITIES	57,598 3	55,870 5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	64 8	65 7
Contingently Redeemable Performance Share Awards	53 2	42 9
TOTAL MEZZANINE EQUITY	118 0	108 6

EQUITY

Common Stock – Par Value – $6 50 Per Share

	2020	2019
Shares Authorized	600,000,000	600,000,000
Shares Issued	515,411,847	514,373,631

	March 31, 2020	December 31, 2019
(20,204,160 Shares were Held in Treasury as of March 31, 2020 and December 31, 2019, Respectively)	3,350 2	3,343 4
Paid-in Capital	6,555.9	6,535 6