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 **September 30, 2021**
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	The NASDAQ Stock Market LLC
American Electric Power Company Inc.	6.125% Corporate Units	AEPPL	The NASDAQ Stock Market LLC
American Electric Power Company Inc.	6.125% Corporate Units	AEPPZ	The NASDAQ Stock Market LLC

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 October 28, 2021
American Electric Power Company, Inc.	503,651,677
	($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	3,680
	($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
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September 30, 2021

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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
ALJ	Administrative Law Judge.
AMI	Advanced Metering Infrastructure.
AMR	Automated Meter Reading.
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 Expanded Net Energy Cost deferral balance.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CARES Act	Coronavirus Aid, Relief, and Economic Security Act signed into law in March 2020.
CCR	Coal Combustion Residual.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A retired, single unit coal-fired generation plant totaling 651 MW located in Conesville, Ohio. The plant was jointly-owned by AGR and a nonaffiliate.

Term	Meaning
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
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.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel X, DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV and DCC XVI, consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	Desert Sky Wind Farm LLC, a 170 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas in which AEP owns a 100% interest.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. DHLC is a non-consolidated VIE of SWEPCo.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
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 August 2020 and March 2019.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
KWh	Kilowatt-hour.

Term	Meaning
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
Maverick	Maverick, part of the North Central Wind Energy Facilities, consists of 287 MWs of wind generation in Oklahoma.
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.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,485 MWs of wind generation.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
Oklaunion Power Station	A retired, single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant was jointly-owned by AEP Texas, PSO and certain nonaffiliated entities.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
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.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants:AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO an SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.

Term	Meaning
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.
SEC	U.S. Securities and Exchange Commission.
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.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
Sundance	Sundance, acquired in April 2021 as part of the North Central Wind Energy Facilities, consists of 199 MWs of wind generation in Oklahoma.
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.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC wholly-owned subsidiaries of TCC and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. In July 2020, the final AEP Texas Central Transition Funding II securitization bond matured.
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.
Traverse	Traverse, part of the North Central Wind Energy Facilities, consists of 999 MWs of wind generation in Oklahoma.
Trent	Trent Wind Farm LLC, a 156 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas in which AEP owns a 100% interest.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.

Term	Meaning
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
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 "Part I – Item 2 Management's Discussion and Analysis of Financial Condition and Results of Operations" of this quarterly 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, costs of compliance with vaccination or testing mandates to AEP, electricity usage, employees including employee reactions to potential vaccination mandates, 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, including favorable tax treatment, and to recover those costs.
- New legislation, litigation and government regulation, including changes to tax laws and regulations, oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or PM and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including coal ash and nuclear fuel.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.

- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber- security threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information, except as required by law. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2020 Annual Report and in Part II of this report.

The Company may use its website as a distribution channel for material company information. Financial and other important information regarding the Company is routinely posted on and accessible through the Company's website at www.aep.com/investors/. In addition, you may automatically receive email alerts and other information about the Company when you enroll your email address by visiting the "Email Alerts" section at www.aep.com/investors/.

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

EXECUTIVE OVERVIEW

Impacts of Severe Winter Weather

In February 2021, severe winter weather impacted the service territories of APCo, KPCo, PSO and SWEPCo resulting in power outages, extensiv damage to infrastructure and disruptions to SPP market conditions. Impacts of the severe winter weather are included below. See Note 4 - Rate Matters for additional information.

Storm Restoration Costs

The impact of the severe winter weather resulted in power outages and extensive damage to transmission and distribution infrastructures across the service territories of APCo, KPCo and SWEPCoAs of September 30, 2021, an estimated $67 million of capital expenditures and $149 million of restoration expenses have been incurred related to the severe winter weather. Approximately $142 million of the expenses represent incremental restoration expenses and have been deferred as regulatory assets. The KPSC and LPSC issued orders authorizing the deferral of incremental restoration expenses as regulatory assets. KPCo intends to seek recovery of these incremental storm restoration costs in their next base rate case while APCo is expected to seek recovery in separate filings. In October 2021, SWEPCo requested recovery of these storm costs, in addition to storm costs from Hurricanes Delta and Laura, in a filing with the LPSCAs part of the filing, SWEPCo requested recovery of the carrying charges on the regulatory asset at a weighted average cost of capital through a rider beginning in January 2022. If any of the restoration costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Impacts in SPP

The severe winter weather also had a significant impact in SPP resulting in the declaration of Energy Emergency Alert Levels 2 and 3 for the first time in SPP's history. The winter storm increased the demand for natural gas and restricted the available natural gas supply resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system.

Retail Customers

As of September 30, 2021, PSO and SWEPCo have deferred regulatory assets of $673 million and $433 million, respectively, relating to natural gas expenses and purchases of electricity incurred from February 9, 2021, to February 20, 2021, as a result of severe winter weather. SWEPCo's deferred regulatory asset consists of $107 million, $151 million and $175 million related to the Arkansas, Louisiana and Texas jurisdictions, respectively. PSO and SWEPCo have active fuel clauses that allow for the recovery of prudently incurred fuel and purchased power expensesGiven the significance of these costs, PSO and SWEPCo expect the costs to be subject to prudency reviews. Management believes these costs are probable of future recovery, but expects the recovery period to be extended to mitigate the impact on customer bills.

In March 2021, the APSC issued an order authorizing recovery of the Arkansas jurisdictional share of the retail customer fuel costs over five years, with the appropriate carrying charge to be determined at a later date. Accordingly, in April 2021, SWEPCo began recovery of its Arkansas jurisdictional share of these fuel costs, which are subject to true-up by the APSC.SWEPCo is recovering these fuel costs at an interim carrying charge of 0.8%. Also in April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05% which has been supported by APSC staff. Various other parties have recommended recovery periods ranging from 5-20 years with a carrying charge of 1.65%. The APSC ordered more testimony regarding the option of utilizing securitization to recover the fuel costs. SWEPCo is awaiting a decision from the APSC.The prudency of these fuel costs is expected to be addressed in a separate proceeding.

In March 2021, the LPSC approved a special order granting a temporary modification to the FAC that allows SWEPCo to recover the Louisiana jurisdictional share of these retail fuel costs over a longer period than what the FAC traditionally allows. In April 2021, SWEPCo began recovery of its Louisiana jurisdictional share of these fuel costs based on a five year recovery period. SWEPCo is recovering these fuel costs at an interim carrying charge of 3.25%. SWEPCo will work with the LPSC to finalize the actual recovery period and determine the appropriate carrying charge in future proceedings.

In April 2021, the OCC approved a waiver for PSO allowing the deferral of the extraordinary fuel and purchase of electricity costs, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. Also in April 2021, legislation was enacted in Oklahoma to permit securitization of the extraordinary fuel and purchase of electricity costs impacting the utilities within the state. Under the legislation, the OCC has the authority to determine, after receiving an application from a rate-regulated utility, if the extraordinary fuel and purchase of electricity costs incurred in February 2021 may be mitigated through securitization to reduce the impact on customer bills. PSO has filed an application for a financing order to pursue securitization. The application requests an order on the prudency of the extraordinary fuel and purchase of electricity costs and a carrying charge of the commission authorized weighted average cost of capital until securitization bonds can be issued. In October 2021, OCC staff and intervenors filed testimony supporting securitization of these costs and a carrying charge until costs are securitized ranging from the interim rate of 0.75% to the actual cost of capital used to finance the costs of 2.32%. In addition, OCC staff supported the prudency of PSO's requested costs while one intervenor recommended disallowances of up to $40 million. A procedural schedule has been set with an ALJ report to be filed in January 2022. An order from the OCC is expected in the first quarter of 2022.

In August 2021, SWEPCo filed an application with the PUCT to implement a net interim fuel surcharge for the Texas jurisdictional share of these retail fuel costs. The application supported a five-year recovery at a carrying charge of 7.18%. In October 2021, various intervenors filed testimony supporting a five-year recovery with a carrying charge ranging from 0.082% to 1.625%. A hearing with the PUCT is scheduled for November 2021.

Wholesale Customers

During the first quarter of 2021, SWEPCo billed wholesale customers $104 million resulting from the severe winter weather events.SWEPCo worked with wholesale customers to establish payment terms for the outstanding accounts receivable. As of September 30, 2021, $56 million of accounts receivable from wholesale customers are outstanding. Management believes these receivables are probable of future collection.

PSO and SWEPCo Cash Flow Implications

PSO and SWEPCo evaluated financing alternatives to address the timing difference between the payment of the estimated natural gas expenses and purchases of electricity to suppliers and subsequent recovery from customers. In March 2021, PSO drew $100 million on its revolving credit facility and SWEPCo issued $500 million of Senior Unsecured NotesIn March 2021, Parent entered into a $500 million 364-day Term Loan and borrowed the full amount. The proceeds from this loan were used to help fund capital contributions to PSO and SWEPCo totaling $425 million and $100 million, respectively. In April 2021, PSO received an additional capital contribution from Parent of $125 million to further address these costs.

Although the February 2021 severe winter weather did not materially impact AEP’s results of operations for the three and nine months ended September 30, 2021, if either PSO or SWEPCo is unable to recover these fuel and purchased power costs, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

COVID-19

In 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 resulted in reduced demand for energy, particularly from commercial and industrial customers. In 2021, weather-normalized customer demand has improved from the pandemic levels experienced in 2020. Management expects continued improvement during the remainder of 2021 as additional vaccinations occur and economic activity improves.

During 2020, AEP's electric operating companies informed both retail customers and state regulators that disconnections for non-payment were temporarily suspended. Shortly thereafter, AEP's state regulators also imposed temporary moratoria on customary disconnection practices. As of September 30, 2021, AEP's electric operating companies have resumed customary disconnection practices in all regulated jurisdictions with the exception of residential customers in Virginia. AEP continues to work with regulators and stakeholders in Virginia and management currently anticipates resuming customary disconnection practices once available relief funds are received from the state.

AEP has been and continues to be proactive in engaging with customers to collect payments or establish payment arrangements for outstanding balances. As of September 30, 2021, AEP currently does not expect accounts receivable aging to have a material adverse impact on the Registrants' allowance for uncollectible accounts based on considerations of the COVID-19 impacts and past trends during times of economic instability. Management continues to monitor developments that could have an impact on customer collections.

The Registrants continue to take steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19As of September 30, 2021, there has been no material adverse impact to the Registrants' business operations and customer service as a result of the current remote work model. In the second quarter of 2021, management announced a Future of Work model designating employees as: (a) On-Site employees, (b) Hybrid employees and (c) Remote employees. Management began transitioning On-Site employees back to their AEP workplace and Hybrid employees with set schedules back to their AEP workplace in October 2021. Remote employees are scheduled to begin transitioning back to their AEP workplace in November 2021 on an as-needed basis. Management will continue to review and modify plans as conditions change.

In 2021, the Registrants have experienced certain supply chain disruptions driven by several factors including staffing and travel issues caused by the COVID-19 pandemic, increased demand due to the economic recovery from the pandemic, labor shortages in certain trades and shortages in the availability of certain raw materials. These supply chain disruptions have not had a material impact on the Registrants net income, cash flows and financial condition, but have extended lead times for certain goods and services. Management has implemented risk mitigation strategies in an attempt to mitigate the impacts of these supply chain disruptions. However, a prolonged continuation or a future increase in the severity of supply chain disruptions could impact the cost of certain goods and services and extend lead times which could reduce future net income and cash flows and impact financial condition.

Customer Demand

AEP's weather-normalized retail sales volumes for the third quarter of 2021 increased by 3% from the third quarter of 2020. Weather-normalized residential sales decreased by 1.6% in the third quarter of 2021 from the third quarter of 2020. AEP's third quarter 2021 industrial sales volumes increased by 7% compared to the third quarter of 2020. The increase in industrial sales was spread across many industries. Weather-normalized commercial sales increased 5% in the third quarter of 2021 from the third quarter of 2020.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2021 increased by 2.3% compared to the nine months ended September 30, 2020. Weather-normalized residential sales decreased by 0.9% for the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020. AEP's industrial sales volumes for the nine months ended September 30, 2021 increased 4.2% compared to the nine months ended September 30, 2020. The recovery in industrial sales volumes was spread across many industries. Weather-normalized commercial sales increased 4.3% for the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020.

The current year increase in industrial and commercial sales volumes is primarily driven by a recovery from the COVID-19 pandemic.In 2020, public health restrictions significantly disrupted economic activity and industrial and commercial demand for energy in AEP's service territory. Similarly, the current year decline in weather-normalized residential sales volumes is driven by the cessation of stay at home restrictions that were in place in 2020 and the gradual return of customers to the workplace.

AEP revised its forecast for 2021 weather-normalized retail sales volumes in September 2021 from the forecast presented in the 2020 10-K.In 2021, AEP currently anticipates weather-normalized retail sales volumes will increase by 2.2%. AEP expects industrial class sales volumes to increase by 4.3% in 2021, while weather-normalized residential sales volumes are projected to decrease by 0.9%. Finally, AEP currently projects weather-normalized commercial sales volumes to increase by 3.7%.

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(a) Percentage change for the year ended December 31, 2020 as compared to the year ended December 31, 2019.
(b) As presented in the 2020 AEP 10-K: Forecasted percentage change for the year ending December 31, 2021 compared to the year ended December 31, 2020.
(c) Revised in September 2021: Forecasted percentage change for the year ending December 31, 2021 compared to the year ended December 31, 2020.

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.

- *2017-2019 Virginia Triennial Review* - In November 2020, the Virginia SCC issued an order on APCo's 2017-2019 Triennial Review filing concluding that APCo earned above its authorized ROE but within its ROE band for the 2017-2019 period, resulting in no refund to customers and no change to APCo base rates on a prospective basis. The Virginia SCC approved a prospective 9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a 140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top).

  In December 2020, an intervenor filed a petition at the Virginia SCC requesting reconsideration of: (a) the failure of the Virginia SCC to apply a threshold earnings test to the approved regulatory asset for APCo's closed coal-fired generation assets, (b) the Virginia SCC's use of a 2011 benchmark study to measure the replacement value of capacity for purposes of APCo's 2017 – 2019 earnings test and (c) the reasonableness and prudency of APCo's investments in AMI meters.

  In December 2020, APCo filed a petition at the Virginia SCC requesting reconsideration of: (a) certain issues related to APCo's going-forward rates and (b) the Virginia SCC's decision to deny APCo tariff changes that align rates with underlying costs.For APCo's going-forward rates, APCo requested that the Virginia SCC clarify its final order and clarify whether APCo's current rates will allow it to earn a fair return. If the Virginia SCC's order did conclude on APCo's ability to earn a fair return through existing base rates, APCo further requested that the Virginia SCC clarify whether it has the authority to also permit an increase in base rates.

  In March 2021, the Virginia SCC issued an order confirming certain of its decisions from the November 2020 order and rejecting the various requests for reconsideration from APCo and an intervenor. In confirming its decision to reject an intervenor's recommendation that APCo's AMI costs incurred during the triennial period be disallowed, the Virginia SCC clarified that APCo established the need to replace its existing AMR meters, and that based on the uncertainty surrounding the continued manufacturing and support of AMR technology, APCo reasonably chose to replace them with AMI meters. In March 2021, APCo filed a notice of appeal of the reconsideration order with the Virginia Supreme Court. In September 2021, APCo submitted its brief before the Virginia Supreme Court.The brief was in alignment with the assignments of error filed by APCo in March 2021. In October 2021, the Virginia SCC and certain intervenors filed briefs with the Virginia Supreme Court disagreeing with APCo's assignments of error in its appeal of the Triennial Review decision.Additionally, the Virginia SCC and APCo filed briefs disagreeing with an intervenor' s assignments of error in a separate appeal of the same decision.

  APCo ultimately seeks an increase in base rates through its appeal to the Virginia Supreme Court.Among other issues, this appeal includes APCo's request for proper treatment of the closed coal-fired plant assets in APCo's 2017-2019 triennial period, reducing APCo's earnings below the bottom of its authorized ROE band. If APCo's appeals regarding treatment of the closed coal plants are granted by the Virginia Supreme Court, it could initially reduce future net income and impact financial condition. The initial negative impact for the write-off of closed coal-fired plant asset balances would potentially be partially offset by an increase in base rates for earning below APCo's 2017-2019 authorized ROE band.

- *2020 Ohio Base Rate Case*- In June 2020, OPCo filed a request with the PUCO for a $42 million annual increase in base rates based upon a proposed 10.15% ROE net of existing riders. In March 2021, OPCo, the PUCO staff and various intervenors filed a joint stipulation and settlement agreement with the PUCO based upon an annual revenue decrease of $68 million and an ROE of 9.7%.The difference between OPCo's requested annual base rate increase and the agreed upon decrease is primarily due to a reduction in the requested ROE, the removal of proposed future energy efficiency costs and a decrease in vegetation management expenses moved to recovery in riders. In addition, the joint stipulation and settlement agreement includes an increased fixed monthly residential customer charge, the discontinuation of rate decoupling and the continuation of the DIR with annual revenue caps of $57 million in 2021, $91 million in 2022, $116 million in 2023 and $51 million for the first five months of 2024. Annual revenue caps for the DIR can be increased if OPCo achieves certain reliability standards. A hearing took place with the PUCO in May 2021 and initial briefs were filed in June 2021 followed by reply briefs in July 2021. An order from the PUCO is expected in the fourth quarter of 2021.

- *Hurricane Laura* - In August 2020, Hurricane Laura hit the coasts of Louisiana and Texas, causing power outages to more than 130,000 customers across SWEPCo's service territories. Prior to Hurricane Laura, SWEPCo did not have a catastrophe reserve or automatic deferral authority within any of its jurisdictions. In October 2020, the LPSC issued an order allowing Louisiana utilities, including SWEPCo, to establish a regulatory asset to track and defer expenses associated with Hurricane Laura. In October 2020, as part of the 2020 Texas Base Rate Case, SWEPCo requested deferral authority of incremental other operation and maintenance expenses. As of September 30, 2021, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $92 million ($89 million of which has been deferred as a regulatory asset related to the Louisiana jurisdiction) and incremental capital expenditures of $18 million, all of which is related to the Louisiana jurisdiction. In October 2021, SWEPCo requested recovery of these storm costs, in addition to SWEPCo's various other storm costs, in a filing with the LPSC.

- *2012 Texas Base Rate Case* - In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC. Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals. In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court.

  In March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant. In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgement affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. SWEPCo disagrees with the Court of Appeals decision and expects to submit a Petition for Review with the Texas Supreme Court in November 2021.

  If SWEPCo is ultimately unable to recover capitalized Turk Plant costs including AFUDC in excess of the Texas jurisdictional capital cost cap it would result in a pretax net disallowance ranging from $80 million to $100 million. In addition, if AFUDC is ultimately determined to be included in the Texas jurisdictional capital cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $160 million related to revenues collected from February 2013 through September 2021 and such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis.

- In July 2019, Ohio House Bill 6 (HB 6), which offered incentives for power-generating facilities with zero or reduced carbon emissions, was signed into law by the Ohio Governor. HB 6 phased out current energy efficiency programs as of December 31, 2020, including OPCo's shared savings revenues of $26 million annually and renewable mandates after 2026. HB 6 also provided for the recovery of existing renewable energy contracts on a bypassable basis through 2032 and included 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. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of the Speaker of the Ohio House of Representatives, Larry Householder, four other individuals, and Generation Now, an entity registered as a 501(c)(4) social welfare organization, in connection with an alleged racketeering conspiracy involving the adoption of HB 6. Certain defendants in that case have since pleaded guilty. In August 2020, an AEP shareholder filed a putative class action lawsuit against AEP and certain of its officers for alleged violations of securities laws in connection with HB 6. On May 10, 2021, the defendants filed a motion to dismiss the securities litigation for failure to state a claim, which was fully briefed on July 26, 2021. Oral arguments on the motion to dismiss is scheduled for November 23, 2021. In addition, four AEP shareholders have filed derivative actions purporting to assert claims on behalf of AEP against certain AEP officers and directors, all of which are currently stayed. See Litigation Related to Ohio House Bill 6 section of Litigation below for additional information.

In March 2021, the Governor of Ohio signed legislation that, among other things, rescinded the payments to the nonaffiliated owner of Ohio's nuclear power plants that were previously authorized under HB 6. The new legislation, House Bill 128, went into effect after 90 days and leaves unchanged other provisions of HB 6 regarding energy efficiency programs, recovery of renewable energy costs and recovery of OVEC costs. 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 incurs significant costs associated with the securities class action or the derivative actions, it could reduce future net income and cash flows and impact financial condition.

- In December 2020, APCo and WPCo filed a proposal with the WVPSC to implement an investment tracker surcharge mechanism for recovering costs associated with capital investment made between base rate cases. The initial filing requested a total annual increase of $50 million ($41 million related to APCo), which represents recovery of costs associated with infrastructure investments made over an approximate three-year period since the companies' last base rate case filing in 2018. The filing also proposed that APCo and WPCo could submit annual filings with requested increases capped to a percentage of total retail revenues (3.5% in the first year and 3% in subsequent filings with an overall cap of 9.5%).

  In June 2021, the WVPSC issued an order approving the investment tracker mechanism with an initial annual revenue requirement of $44 million ($36 million related to APCo) effective September 2021 based on a 9.25% ROE.The order also allows APCo and WPCo to request future year investment tracker increases for assets placed in service during the most recent 12-month period ending September 30th, subject to an annual three percent rider increase cap on base year total retail revenues. Under the conditions of the order and with certain exceptions as outlined by the WVPSC, APCo and WPCo are prohibited from filing a base rate case before June 30, 2024.

- In April 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (NOPR) proposing to modify its incentive for transmission owners that join RTOs (RTO Incentive). Under the supplemental NOPR, the RTO Incentive would be modified such that a utility would only be eligible for the RTO Incentive for the first three years after the utility joins a FERC-approved Transmission Organization.This is a significant departure from a previous NOPR issued in 2020 seeking to increase the RTO Incentive from 50 basis points to 100 basis points. The supplemental NOPR also required utilities that have received the RTO Incentive for three or more years to submit, within 30 days of the effective date of a final rule, a compliance filing to eliminate the incentive from its tariff prospectively. The supplemental NOPR was subject to a 60 day comment period followed by a 30 day period for reply comments. In July 2021, AEP submitted reply comments. A final rule could be issued in the fourth quarter of 2021.

  In 2019, the 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 2020, the FERC determined the base ROE for MISO's transmission owning subsidiaries should be 10.02% (10.52% inclusive of RTO Incentive adder of 0.5%).

  In July 2021, the FERC issued an order denying Dayton Power and Light's request for a 50 basis point RTO incentive on the basis that its RTO participation was not voluntary, but rather is required by Ohio law.

This precedent could have an impact on AEP's transmission owning subsidiaries whose RTO membership is not voluntary, including OPCo and AEP Ohio Transmission Company.

If the FERC modifies its RTO Incentive policy, it would be applied, as applicable, to AEP's PJM, SPP and MISO transmission ownin subsidiaries on a prospective basis, and could affect future net income and cash flows and impact financial condition. Based on management's preliminary estimates, if a final rule is adopted consistent with the April 2021 supplemental NOPR, it could reduce AEP's pretax income by approximately $55 million to $70 million on an annual basis.

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' pending base rate case proceedings in 2021. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase		Approved ROE	New Rates Effective
		(in millions)			
KPCo	Kentucky	$ 52.7	(a)	9.3%	January 2021

(a) See "2020 Kentucky Base Rate Case" section of Note 4 Rate Matters in the 2020 Annual Report for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase (in millions)		Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE	
OPCo	Ohio	June 2020	$ 42.3		10.15%	8.76%-9.78%	(a)
SWEPCo	Texas	October 2020	100.4	(b)	10.35%	9%-9.22%	(c)
SWEPCo	Louisiana	December 2020	94.7		10.35%	9.1%-9.8%	(d)
PSO	Oklahoma	April 2021	127.5		10%	9%-9.4%	(e)
I&M	Indiana	July 2021	104.0	(f)	10%	9.1%-9.3%	(g)
SWEPCo	Arkansas	July 2021	85.0		10.35%	(h)	

(a) In March, 2021 a joint stipulation and settlement agreement was filed with the PUCO which included a $68 million decrease in base rates based upon a ROE of 9.7%.
(b) The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $85 million primarily due to increased investments.
(c) An ALJ proposed a base rate increase of $41 million based upon a ROE of 9.45%.
(d) LPSC staff recommended a base rate increase of $6 million.
(e) In September 2021, a contested joint stipulation and settlement agreement was filed with the OCC which included a $51 million increase in base rates based upon a ROE of 9.4%.
(f) Proposed to be phased-in with a $73 million annual increase effective May 2022 and the remaining $31 million annual increase effective January 2023.
(g) Intervenors proposed a decrease in base rates ranging from $13 million to $68 million.
(h) Intervenor testimony is expected in December 2021.

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 September 30, 2021, subsidiaries within AEP's Generation & Marketing segment had approximately 1,633 MWs of contracted renewable generation projects in-service. In addition, as of September 30, 2021, these subsidiaries had approximately 155 MWs of renewable generation projects under construction with total estimated capital costs of $221 million related to these projects.

Regulated Renewable Generation Facilities

In 2020, PSO received approval from the OCC and SWEPCo received approval from the APSC and LPSC to acquire the NCWF, comprised of thr Oklahoma wind facilities totaling 1,485 MWs, on a fixed cost turn-key basis at completion. Both the APSC and LPSC approved the flex-up option, agreeing to acquire the Texas portion, which the PUCT denied. PSO will own 45.5% and SWEPCo will own 54.5% of the project, which will cost approximately $2 billion.

In June 2021, the IRS issued a notice extending the "Continuity Safe Harbor" deadlines for qualifying renewable energy projects. Under the June 2021 IRS notice, the Continuity Safe Harbor for qualifying renewable energy projects that began construction in calendar years 2016 through 2019 is extended to six years. Additionally, the Continuity Safe Harbor is extended to five years for qualifying projects that began construction in calendar year 2020. Provided that each facility does satisfy the Continuity Safe Harbor, under the current IRS guidance, the Sundance wind facility will qualify for 100% of the federal PTC, and the Maverick and Traverse wind facilities will qualify for 80% of the federal PTC.

In April 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Sundance during its development anc construction for $270 million, the first of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entit and simultaneously distributed the Sundance assets in proportion to their undivided ownership interests. Sundance was placed in-service in April 2021. In September 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Maverick during its developmen and construction for $383 million, the second of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated th entity and simultaneously distributed the Maverick assets in proportion to their undivided ownership interests. Maverick was placed in-service in September 2021. As of September 30, 2021, PSO and SWEPCo had approximately $314 million and $376 million, of Property, Plant and Equipment o the balance sheets, respectively, related to the Sundance and Maverick NCWF projects.The Traverse wind facility is targeted to be acquired and placed in-service between January and April 2022. See Note 6 - Acquisitions for additional information.

In June 2021, SWEPCo issued requests for proposals to acquire up to 3,000 MWs of wind and 300 MWs of solar generation resourcesThe wind and solar generation projects would be subject to regulatory approval.

In September 2021, PSO issued draft requests for proposals to acquire up to 2,600 MWs of wind and 1,350 MWs of solar generation resourcesThe wind and solar generation projects would be subject to regulatory approval.

Disposition of KPCo and AEP Kentucky Transmission Company, Inc. (KTCo)

In October 2021, AEP entered into a Stock Purchase Agreement to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Oakville, Ontari Canada based Algonquin Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value.The sale is subject to regulatory approvals from the FERC, the KPSC, clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and clearance from th Committee on Foreign Investment in the United States.

KPCo currently operates and owns a 50% interest in the 1,560 MW coal-fired Mitchell Power Plant (Mitchell Plant) with the remaining 50% owned by WPCo.The Stock Purchase Agreement is further contingent upon approval by the KPSC, WVPSC and FERC of a new proposed Mitchell Pla Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo will replac KPCo as the operator of the Mitchell Plant and KPCo employees at the Mitchell Plant will become employees of WPCo at closing of the transaction Under the proposed Ownership Agreement, WPCo is obligated to purchase KPCo's 50% interest in the Mitchell Plant on December 31, 2028 unless KPCo and WPCo have agreed to retire the Mitchell Plant earlier or, absent such agreement, if WPCo elects prior to December 31, 2027 to retire the Mitchell Plant on December 31, 2028. The Ownership Agreement provides that the purchase price for KPCo's 50% ownership interest in the Mitchell Plant will be determined through the mutual agreement of WPCo and KPCo (subject to approval from the KPSC and WVPSC) or through a fa market valuation determination conducted by independent appraisals if KPCo and WPCo are unable to reach agreement as to the purchase price.

The sale is expected to close in the second quarter of 2022 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction.

AEP expects to receive approximately $1.45 billion in cash, net of taxes and transaction fees. AEP plans to use the proceeds to eliminate forecasted equity needs in 2022 as the company invests in regulated renewables, transmission and other projects. AEP expects the sale to have a one-time, immaterial impact on after-tax earnings.

Racine

In February 2021, AEP signed an agreement to sell Racine to a nonaffiliated party. As of September 30, 2021, the net book value of Racine was $45 million. The sale of Racine was approved by the U.S. Army Corps of Engineers in the third quarter of 2021.The sale also requires approval from the FERC.The sale is expected to close in the fourth quarter of 2021 and result in an immaterial gain. Racine was not presented as Held for Sale on AEP's balance sheets due to immateriality.

Dolet Hills Power Station and Related Fuel Operations

DHLC provides 100% of the fuel supply to Dolet Hills Power StationDuring the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In 2020, management of SWEPCo and CLECO determined DHLC would not proceed developing additional Oxbow Lignite Company (Oxbow) mining areas for future lignite extraction and ceased extraction of lignite at the mine in May 2020.Based on these actions, management revised the estimated useful life of DHLC's and Oxbow's assets to coincide with the date at which extraction was discontinued in the second quarter of 2020 and the date at which delivery of lignite ceased in October 2021. In addition, management also revised the useful life of the Dolet Hills Power Station to 2021 based on the remaining estimated fuel supply available for continued seasonal operation.In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining.

The Dolet Hills Power Station non-fuel costs are recoverable by SWEPCo through base ratesAs of September 30, 2021, SWEPCo's share of the net investment in the Dolet Hills Power Station is $146 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 fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $44 million as of September 30, 2021. Also, as of September 30, 2021, SWEPCo had a net under-recovered fuel balance of $39 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Dolet Hills Power Station. Additional operational, reclamation and other land-related costs incurred by DHLC and Oxbow will be billed to SWEPCo and included in future fuel clauses.

In June 2020, SWEPCo filed a fuel reconciliation with the PUCT for its retail operations in Texas, including Dolet Hills, for the reconciliation period of March 1, 2017 to December 31, 2019. See "2020 Texas Fuel Reconciliation" section of Note 4 for additional information.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $30 million of additional costs with a recovery period to be determined at a later date.

In March 2021, the APSC approved fuel rates that provide recovery of the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

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

Pirkey Power Plant and Related Fuel Operations

In 2020, management announced plans to retire the Pirkey Power Plant in 2023.The Pirkey Power Plant non-fuel costs are recoverable by SWEPCo through base rates and fuel costs are recovered through active fuel clauses. As of September 30, 2021, SWEPCo's share of the net investment in the Pirkey Power Plant is $203 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Power Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $108 million as of September 30, 2021. Also, as of September 30, 2021, SWEPCo had a net under-recovered fuel balance of $39 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Pirkey Power Plant.Additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in future fuel clauses.If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies for additional information.

Rockport Plant Litigation

In 2013, the Wilmington Trust Company filed suit 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 sought a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. See "Obligations under the New Source Review Litigation Consent Decree" section below for additional information.

After the litigation proceeded at the District Court and Circuit Court levels, on April 20, 2021, I&M and AEGCo reached an agreement to acquire 100% of the interests in Rockport Plant, Unit 2 for $115.5 million from certain financial institutions that own the unit through trusts established by Wilmington Trust, the nonaffiliated owner trustee of the ownership interests in the unit, with closing to occur as of the end of the Rockport Plant, Unit 2 lease in December 2022. The agreement is subject to customary closing conditions, including regulatory approvals and as of the closing will result in a final settlement of, and release of claims in, the lease litigation. As a result, in May 2021, at the parties' request, the district court entered a stipulation and order dismissing the case without prejudice to plaintiffs asserting their claims in a re-filed action or a new action. Management believes its financial statements appropriately reflect the resolution of the litigation.

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 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. The denial of those claims was appealed to the AEP System Retirement Plan Appeal Committee and the Committee upheld the denial of claims. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Litigation Related to Ohio House Bill 6 (HB 6)

In 2019, Ohio adopted and implemented HB 6 which benefits OPCo by authorizing rate recovery for certain costs including renewable energy contracts and OVEC's coal-fired generating units. OPCo engaged in lobbying efforts and provided testimony during the legislative process in connection with HB 6. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of an Ohio legislator and associates in connection with an alleged racketeering conspiracy involving the adoption of HB 6. After AEP learned of the criminal allegations against the Ohio legislator and others relating to HB 6, the Company, with assistance from outside advisors, conducted a review of the circumstances surrounding the passage of the bill. We do not believe that AEP was involved in any wrongful conduct in connection with the passage of HB 6.

In August 2020, an AEP shareholder filed a putative class action lawsuit in the United States District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. The amended complaint alleges misrepresentations or omissions by AEP regarding: (a) its alleged participation in or connection to public corruption with respect to the passage of HB 6 and (b) its regulatory, legislative, political contribution, 501(c)(4) organization contribution and lobbying activities in Ohio. The complaint seeks monetary damages, among other forms of relief. On May 10, 2021, the defendants filed a motion to dismiss the securities litigation for failure to state a claim and the motion was fully briefed as of July 26, 2021. The Court has scheduled oral argument for November 23, 2021 on the motion to dismiss. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In January 2021, an AEP shareholder filed a derivative action in the United States District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The first three derivative actions have been stayed pending the resolution of the motion to dismiss the securities litigation. The fourth has been stayed until such time as the court determines to lift the stay. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

On March 1, 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter is directed to the Board of Directors of AEP and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by directors and officers, and that, following such investigation, the Company commence a civil action for breaches of fiduciary duty and related claims and take appropriate disciplinary action against those individuals who allegedly harmed the company. The shareholder that sent the letter has agreed that AEP and the AEP Board may defer consideration of the litigation demand until the resolution of the motion to dismiss the securities litigation. The AEP Board will act in response to the letter as appropriate. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In May 2021, AEP received a subpoena from the SEC's Division of Enforcement seeking various documents, including documents relating to the benefits to AEP from the passage of HB 6 and documents relating to AEP's financial processes and controls. AEP is cooperating fully with the SEC's subpoena. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this inquiry will have a material impact on our financial condition, results of operations, or cash flows.

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 and in response to rules governing the beneficial use and disposal of coal combustion by-products, clean water 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. 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 September 30, 2021, the AEP System owned generating capacity of approximately 25,000 MWs, of which approximately 12,100 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 $350 million to $700 million through 2027.

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.

Obligations under 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. The consent decree has been modified six times, for various reasons, most recently in 2020. All of the environmental control equipment required by the consent decree has been installed.

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 periodically reviews and revises the NAAQS for criteria pollutants under the CAARevisions tend to increase the stringency of the standards, which in turn may require AEP to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. Most recently, the Biden administration has indicated that it is likely to revisit the NAAQS for ozone and PM, which were left unchanged by the prior administration following its review.Management cannot currently predict if any changes to either standard are likely or what such changes may be, but will continue to monitor this issue and any future rulemakings.

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR) in 2005, which could require power plants and other facilities to install best available retrofit technology to address regional haze in federal parks and other protected areas. CAVR is implemented by the states, through SIPs, or by the Federal EPA, through 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.

Arkansas has an approved regional haze SIP and all of SWEPCo's affected units are in compliance with the relevant requirements.

In Texas, the Federal EPA disapproved portions of the Texas regional haze SIP and 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.Legal challenges to these various rulemakings are pending in both the U.S. Court of Appeals for the Fifth Circuit and the U.S. Court of Appeals for the District of Columbia CircuitManagement cannot predict the outcome of that litigation, although management supports the intrastate trading program as a compliance alternative to source-specific controls and has intervened in the litigation in support of the Federal EPA.

Cross-State Air Pollution Rule

CSAPR is 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.

In January 2021, the Federal EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NO_X budgets in 2021-2024. Management believes it can meet the requirements of the rule in the near term, and is evaluating its compliance options for later years, when the budgets are further reduced.

Climate Change, CO_2 Regulation and Energy Policy

In 2019, the Affordable Clean Energy (ACE) rule established a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. However, in January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it to the Federal EPA. Management is unable to predict how the Federal EPA will respond to the court’s remand.

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. That rule has not been finalized. Management continues to actively monitor these rulemaking activities.

While no federal regulatory requirements to reduce CO_2 emissions are in place, 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 February 2021, 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 an 80% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is net-zero CO_2 emissions from AEP generating facilities by 2050. AEP's total estimated CO_2 emissions in 2020 were approximately 44 million metric tons, a 73% 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. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

Excessive costs to comply with future legislation or regulations have led to the announcement of early plant closures and could force AEP to close additional coal-fired generation facilities earlier than their estimated useful life. If AEP is unable to recover the costs of its investments, it would reduce future net income and cash flows and impact financial condition.

Coal Combustion Residual Rule

The Federal EPA's CCR rule regulates 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 and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers.

In August 2020, the Federal EPA revised the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. The revised rule provides two options that allow facilities to extend the date by which they must cease receipt of coal ash and close the ponds.

The first option provides an extension to cease receipt of CCR no later than October 15, 2023 for most units, and October 15, 2024 for a narrow subset of units; however, the Federal EPA's grant of such an extension will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR. Additionally, each request must undergo formal review, including public comments, and be approved by the Federal EPA. AEP filed applications for additional time to develop alternative disposal capacity at the following plants:

Company	Plant Name and Unit	Generating Capacity	Net Book Value (a)		Projected Retirement Date
		(in MWs)	(in millions)		
AEGCo	Rockport Plant, Unit 1	655	$ 232.0		2028
APCo	Amos	2,930	2,111.7		2040
APCo	Mountaineer	1,320	962.3		2040
I&M	Rockport Plant, Unit 1	655	525.1	(b)	2028
KPCo	Mitchell Plant	780	586.5		2040
SWEPCo	Flint Creek Plant	258	269.2		2038
WPCo	Mitchell Plant	780	588.9		2040

(a) Net book value before cost of removal including CWIP and inventory.
(b) Amount includes a $176 million regulatory asset related to the retired Tanners Creek Plant. The IURC and MPSC authorized recovery of the Tanners Creek Plant regulatory asset over the useful life of Rockport Plant, Unit 1 in 2015 and 2014, respectively.

In addition, AGR owns Cardinal Plant, Unit 1 a competitive generation unit.A nonaffiliate owns Cardinal Plant, Unit 2 and Unit 3 and operates all three units at the Cardinal Plant. The nonaffiliate filed an application for additional time to develop alternative disposal capacity for the Cardinal Plant. As of September 30, 2021, the net book value of Cardinal Plant, Unit 1, including materials and supplies and CWIP, was approximately $43 million.

The second option is a retirement option, which provides a generating facility an extended operating time without developing alternative CCR disposal. Under the retirement option, a generating facility would have until October 17, 2023 to cease operation and to close CCR storage ponds 40 acres or less in size, or through October 17, 2028 for facilities with CCR storage ponds greater than 40 acres in size. Pursuant to this option, AEP informed the Federal EPA of its intent to retire the Pirkey Power Plant and cease using coal at the Welsh Plant:

Company	Plant Name and Unit	Generating Capacity	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Projected Retirement Date
		(in MWs)	(in millions)		
SWEPCo	Pirkey Power Plant	580	$ 135.4	$ 68.0	2023 (b)
SWEPCo	Welsh Plants, Units 1 and 3	1,053	493.7	35.6	2028 (c)(d)

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(c) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(d) Unit 1 is currently being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is currently being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

AEP may incur significant costs to upgrade or close and replace surface impoundments and landfills used to manage CCR and to conduct any required remedial actions. Under the retirement option above, AEP may need to recover remaining depreciation and estimated closure costs associated with retiring plants over a shorter period. If AEP cannot ultimately recover the costs of environmental compliance and/or the remaining depreciation and estimated closure costs associated with retiring plants in a timely manner, it would reduce future net income and cash flows and impact financial condition.

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.

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 have already 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

The Federal EPA's ELG rule for generating facilities establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. A recent revision to the ELG rule, published in October 2020, establishes additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units and extends the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. Management has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. Permit modifications for affected facilities were filed in January 2021 that reflect the outcome of that assessment. We continue to work with state agencies to finalize permit terms and conditions.

In August 2021, the Federal EPA and the Army Corps of Engineers announced their plan to reconsider and revise the Navigable Waters Protection Rule, which defines “waters of the United States” under the Clean Water Act. Shortly thereafter, the United States District Court for the District of Arizona vacated and remanded the Navigable Waters Protection Rule, which had the effect of reinstating the prior, much broader, version of the rule. Because the scope of waters subject to Federal EPA and Army Corps of Engineers jurisdictions is broader under the prior rule, permitting decisions made in recent years are subject to reevaluation; permits may now be necessary where none were previously required, and issued permits may need to be reopened to impose additional obligations. Management will continue to monitor rulemaking on this issue.

CCR and ELG Compliance Plan Filings

Mitchell Plant (Applies to AEP)

KPCo and WPCo each own a 50% interest in the Mitchell Plant. In December 2020 and February 2021, WPCo and KPCo filed requests with the WVPSC and KPSC, respectively, to obtain the regulatory approvals necessary to implement CCR and ELG compliance plans and seek recovery o the estimated $132 million investment for the Mitchell Plant that would allow the plant to continue operating beyond 2028. Within those requests, WPCo and KPCo also filed a $25 million alternative to implement only the CCR-related investments with the WVPSC and KPSC, respectively, whic would allow the Mitchell Plant to continue operating only through 2028.

In July 2021, the KPSC issued an order approving the CCR only alternative and rejecting the full CCR and ELG compliance plan. In August 2021, the WVPSC approved the full CCR and ELG compliance plan for the WPCo share of the Mitchell Plant. In September 2021, WPCo submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021. Due to the rejection by the KPSC of the KPCo share of the ELG investments, WPCo requested the WVPSC consider approving the construction and recovery of all ELG costs at the plant. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed WPCo to proceed wit CCR/ELG compliance plans that would allow the plant to continue operating beyond 2028. The WVPSC’s order further states WPCo will not share capacity and energy from the plant with KPCo customers if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plant to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that WPCo will be given the opportunity to recover, from its customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plant beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. In October 2021, an intervenor filed a petition for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

As of September 30, 2021, the Mitchell Plant ELG investment balance in CWIP was $3 million split equally between KPCo and WPCo. As of September 30, 2021, the net book value of KPCo’s share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $587 million.

If any of the ELG costs are not approved for recovery and/or the retirement date of the Mitchell Plant is accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

Amos and Mountaineer Plants (Applies to AEP and APCo)

In December 2020, APCo submitted filings with the Virginia SCC and WVPSC requesting regulatory approvals necessary to implement CCR an ELG compliance plans and seek recovery of the estimated $240 million investment for the Amos and Mountaineer plants.Intervenors in Virginia and West Virginia recommended that only the CCR-related investments be constructed at Amos and Mountaineer and, as a consequence, that APCo close these generating facilities at the end of 2028.

In August 2021, the Virginia SCC issued an order approving APCo's request to construct CCR-related investments at the Amos and Mountaineer Plants and approved recovery of CCR-related other operation and maintenance expenses and investments through an active rider.The order denied APCo's request to construct the ELG investments and denied recovery of previously incurred ELG costsAPCo may refile for approval of the ELG investments and previously incurred ELG costs at a later date.

Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approve recovery of the West Virginia jurisdictional share of these costs through an active rider. In September 2021, APCo submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021Due to the initial rejection by the Virginia SCC of the Virginia jurisdictional share of the ELG investments, APCo requested the WVPSC consider approving the construction and recovery of all ELG cost at the plants. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed APC to proceed with CCR/ELG compliance plans that would allow the plants to continue operating beyond 2028.The WVPSC's order further states that APCo will not share capacity and energy from the plants with customers from Virginia if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plants to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that APCo will be given the opportunity to recover, from West Virginia customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plants beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. In October 2021, an intervenor filed a petition for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

APCo expects total Amos and Mountaineer Plant ELG investment, including AFUDC, to be approximately $177 millionAs of September 30, 2021, APCo's Virginia jurisdictional share of the net book value, before cost of removal including CWIP and inventory, of the Amos and Mountaineer Plants was approximately $1.5 billion and APCo's Virginia jurisdictional share of its ELG investment balance in CWIP for these plants was $19 million.

If any of the ELG costs are not approved for recovery and/or the retirement dates of the Amos and Mountaineer plants are accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

Impact of Environmental Regulation on Coal-Fired Generation

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal costs and permits. Management continuously evaluates cost estimates of complying with these regulations which may result in a decision to retire coal-fired generating facilities earlier than their currently estimated useful lives.

Previously, management retired or announced early closure plans for Welsh Unit 2, Oklaunion Power Station, Dolet Hills Power Station and Northeastern Plant Unit 3.

The table below summarizes the net book value, as of September 30, 2021, of generating facilities retired or planned for early retirement:

Company	Plant	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Actual/Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (b)
		(in millions)				(in millions)
PSO	Northeastern Plant, Unit 3	$ 175.1	$ 123.6	2026	(c)	$ 14.9
PSO	Oklaunion Power Station	—	33.0	2020	(d)	2.0
SWEPCo	Dolet Hills Power Station	13.0	126.8	2021	(e)	7.7
SWEPCo	Pirkey Power Plant	135.4	68.0	2023	(f)	13.4
SWEPCo	Welsh Plant, Units 1 and 3	493.7	35.6	2028 (g)	(h)	32.9
SWEPCo	Welsh Plant, Unit 2	—	35.2	2016	(i)	—

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) These amounts represent the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Oklaunion Power Station is currently being recovered through 2046.
(e) Dolet Hills Power Station is currently being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Arkansas and Texas jurisdictions.
(f) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(g) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(h) Welsh Plant, Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Welsh Plant, Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.
(i) Welsh Plant, Unit 2 is being recovered over the blended useful life of Welsh Plant, Units 1 and 3.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets are not deemed recoverable, it could materially reduce future net income, cash flows and impact financial condition.

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 standard service offer 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 ROE.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved ROE.

Generation & Marketing

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

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, 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 September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Vertically Integrated Utilities	$ 437.7	$ 393.5	$ 936.3	$ 894.7
Transmission and Distribution Utilities	155.9	147.4	424.0	403.1
AEP Transmission Holdco	166.8	138.3	507.5	370.4
Generation & Marketing	100.7	116.7	189.7	211.0
Corporate and Other	(65.1)	(47.3)	(108.3)	(114.6)
Earnings Attributable to AEP Common Shareholders	$ 796.0	$ 748.6	$ 1,949.2	$ 1,764.6

AEP CONSOLIDATED

Third Quarter of 2021 Compared to Third Quarter of 2020

Earnings Attributable to AEP Common Shareholders increased from $749 million in 2020 to $796 million in 2021 primarily due to:

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

These increases were partially offset by:

- An increase in Other Operation and Maintenance expenses driven by the COVID-19 pandemic which resulted in lower expenses in the second quarter of 2020.
- The recognition of a discrete tax adjustment in 2020 which was attributable to the 5-year net operating loss carryback provision of the CARES Act.
- Unrealized losses on AEP's investment in ChargePoint.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Earnings Attributable to AEP Common Shareholders increased from $1,765 million in 2020 to $1,949 million in 2021 primarily due to:

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

These increases were partially offset by:

- An increase in Other Operation and Maintenance expenses driven by the COVID-19 pandemic which resulted in lower expenses in 2020.
- The recognition of a discrete tax adjustment in 2020 which was attributable to the 5-year net operating loss carryback provision of the CARES Act.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions)			
Revenues	$ 2,759.3	$ 2,434.8	$ 7,557.2	$ 6,753.5
Fuel and Purchased Electricity	855.3	693.7	2,364.7	1,947.0
Gross Margin	1,904.0	1,741.1	5,192.5	4,806.5
Other Operation and Maintenance	796.9	715.9	2,240.6	2,031.8
Depreciation and Amortization	436.3	398.8	1,302.2	1,173.8
Taxes Other Than Income Taxes	124.1	121.0	375.6	355.6
Operating Income	546.7	505.4	1,274.1	1,245.3
Other Income (Expense)	4.1	(0.7)	9.9	2.3
Allowance for Equity Funds Used During Construction	9.6	15.9	30.3	33.1
Non-Service Cost Components of Net Periodic Benefit Cost	17.0	16.9	51.0	50.9
Interest Expense	(144.3)	(140.2)	(425.5)	(426.5)
Income Before Income Tax Expense (Benefit) and Equity Earnings	433.1	397.3	939.8	905.1
Income Tax Expense (Benefit)	(4.6)	3.8	3.4	10.5
Equity Earnings of Unconsolidated Subsidiary	1.0	0.7	2.5	2.2
Net Income	438.7	394.2	938.9	896.8
Net Income Attributable to Noncontrolling Interests	1.0	0.7	2.6	2.1
Earnings Attributable to AEP Common Shareholders	$ 437.7	$ 393.5	$ 936.3	$ 894.7

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions of KWhs)			
Retail:				
Residential	9,119	9,066	25,125	24,304
Commercial	6,468	6,257	17,396	16,773
Industrial	8,485	8,161	24,798	24,335
Miscellaneous	604	595	1,672	1,636
Total Retail	24,676	24,079	68,991	67,048
Wholesale (a)	5,713	4,574	14,842	13,116
Total KWhs	30,389	28,653	83,833	80,164

(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 September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in degree days)			
Eastern Region				
Actual – Heating (a)	1	3	1,710	1,456
Normal – Heating (b)	4	4	1,742	1,752
Actual – Cooling (c)	847	867	1,209	1,204
Normal – Cooling (b)	744	739	1,087	1,081
Western Region				
Actual – Heating (a)	—	1	993	699
Normal – Heating (b)	1	1	901	902
Actual – Cooling (c)	1,485	1,291	2,163	2,015
Normal – Cooling (b)	1,410	1,416	2,137	2,144

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2020	$	393.5
Changes in Gross Margin:		
Retail Margins		142.2
Margins from Off-system Sales		(0.1)
Transmission Revenues		18.2
Other Revenues		2.6
Total Change in Gross Margin		162.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(81.0)
Depreciation and Amortization		(37.5)
Taxes Other Than Income Taxes		(3.1)
Other Income		4.8
Allowance for Equity Funds Used During Construction		(6.3)
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(4.1)
Total Change in Expenses and Other		(127.1)
Income Tax Expense		8.4
Equity Earnings of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interests		(0.3)
Third Quarter of 2021	$	437.7

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

- **Retail Margins** increased $142 million primarily due to the following:
  - A $42 million increase at APCo and WPCo due to rider revenues primarily in Virginia.This increase was partially offset in other expense items below.
  - A $40 million increase at I&M primarily due to an increase in rider revenues and the reversal of a provision for refund. This increase was partially offset in other expense items below.
  - A $24 million increase in weather-related usage primarily in the residential class.
  - A $22 million increase in revenue from rate riders at PSO. This increase was partially offset in other expense items below.
  - A $15 million increase due to lower customer refunds related to Tax Reform primarily at APCo and WPCo.This increase was partially offset in Income Tax Expense below.
  - An $11 million increase at KPCo due to rider revenues. This increase was partially offset in other expense items below.
  - A $9 million increase at KPCo due to base rate case revenues implemented in January 2021.

  These increases were partially offset by:
  - A $15 million decrease in weather-normalized retail margins driven by a $26 million decrease in the residential class partially offset by a $10 million increase in the industrial and commercial classes.
  - A $9 million decrease at PSO due to PTC benefits provided to customers. This decrease is offset in Income Tax Expense.

- An $8 million decrease in deferred fuel at APCo and WPCo primarily due to the timing of recoverable PJM expenses.
- **Transmission Revenues** increased $18 million primarily due to:
  - An $8 million increase due to increased transmission investment at APCo. This increase is partially offset in Depreciation and Amortization expenses below.
  - A $7 million increase in load and transmission investment at SWEPCo.

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

- **Other Operation and Maintenance** expenses increased $81 million primarily due to the following:
  - A $58 million increase in PJM transmission service expenses.
  - A $23 million increase in vegetation management expenses.
  - A $17 million increase in administrative and general expenses.
  - A $13 million increase in SPP transmission service expenses.

  These increases were partially offset by:
  - A $34 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses increased $38 million primarily due to a higher depreciable base at APCo, I&M, PSO and SWEPCo and an increase in depreciation rates at APCo. This increase was partially offset in Gross Margin above.
- **Other Income** increased $5 million primarily related to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event at SWEPCo.
- **Allowance for Equity Funds Used During Construction** decreased $6 million primarily due to the adoption of the FERC's temporary AFUDC waiver which was implemented in July 2020 retroactive to March 2020.
- **Interest Expense** increased $4 million primarily due to increased long-term debt balances at I&M and SWEPCo.
- **Income Tax Expense** decreased $8 million primarily due to a decrease in state income tax expense and an increase in PTC. This decrease was partially offset by an increase in pretax book income and a decrease in parent company loss benefit.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2020	$	894.7
Changes in Gross Margin:		
Retail Margins		336.7
Margins from Off-system Sales		23.7
Transmission Revenues		29.4
Other Revenues		(3.8)
Total Change in Gross Margin		386.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(208.8)
Depreciation and Amortization		(128.4)
Taxes Other Than Income Taxes		(20.0)
Other Income		7.6
Allowance for Equity Funds Used During Construction		(2.8)
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		1.0
Total Change in Expenses and Other		(351.3)
Income Tax Expense		7.1
Equity Earnings of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interests		(0.5)
Nine Months Ended September 30, 2021	$	936.3

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 $337 million primarily due to the following:
  - An $88 million increase at I&M due to the annual wholesale formula rate true-up, an increase in Indiana and Michigan base rate revenues and an increase in rider revenues. This increase was partially offset in other expense items below.
  - An $84 million increase in weather-related usage primarily in the residential class.
  - A $66 million increase at APCo and WPCo due to rider revenue in Virginia and West Virginia.This increase was partially offset in other expense items below.
  - A $41 million increase at PSO due to rider revenues. This increase was partially offset in other expense items below.
  - A $38 million increase at KPCo due to rider revenues. This increase was partially offset in other expense items below.
  - A $20 million increase at KPCo due to base rate case revenues implemented in January 2021.
  - A $13 million increase in municipal and cooperative revenues at SWEPCo primarily due to the February 2021 severe winter weather event.
  - A $12 million increase due to lower customer refunds related to Tax Reform primarily at APCo and WPCo.This increase was partially offset in Income Tax Expense below.
  - A $10 million increase in recoverable fuel costs at SWEPCo primarily due to timing of recovery.
  - A $6 million increase in municipal and cooperative revenues at SWEPCo primarily due to the annual generation formula rate true-up.

These increases were partially offset by:
  - A $32 million decrease in weather-normalized retail margins primarily in the residential class.
  - A $24 million decrease in weather-normalized wholesale margins, including the loss of a significant wholesale contract at I&M.
  - An $11 million decrease at PSO due to PTC benefits provided to customers. This decrease is offset in Income Tax Expense.
- **Margins from Off-system Sales** increased $24 million primarily due to Turk Plant merchant sales as a result of the February 2021 severe winter weather event at SWEPCo.
- **Transmission Revenues** increased $29 million primarily due to the following:
  - A $22 million increase due to increased transmission investment at APCo. This increase is partially offset in Depreciation and Amortization expenses below.
  - A $12 million increase due to increased load and increased transmission investment at SWEPCo.

  These increases were partially offset by:
  - A $7 million decrease as a result of the transmission formula rate true-up.
- **Other Revenues** decreased $4 million primarily due to the following:
  - A $6 million decrease at PSO primarily due to lower business development revenue. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $2 million decrease primarily due to lower pole attachment revenue at KPCo.

  These decreases were partially offset by:
  - A $4 million increase at I&M primarily due to an increase in reconnection fees and joint license agreements.

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

- **Other Operation and Maintenance** expenses increased $209 million primarily due to the following:
  - A $131 million increase in PJM transmission service expenses including the annual formula rate true-up.
  - A $56 million increase in vegetation management expenses.
  - A $50 million increase in SPP transmission service expenses including the annual formula rate true-up.
  - A $10 million increase in administrative overheads.
  - An $8 million increase due to the capitalization of previously expensed North Central Wind Energy Facilities costs at PSO and SWEPCo in 2020.

  These increases were partially offset by:
  - A $20 million decrease primarily due to a decrease in Indiana jurisdictional Demand Side Management expenses at I&M.This decrease was offset in Retail Margins above.
  - A $14 million decrease in employee-related expenses.
  - An $11 million decrease in factoring expenses.
- **Depreciation and Amortization** expenses increased $128 million primarily due to a higher depreciable base at APCo, I&M, PSO and SWEPCo and increased depreciation rates at APCo and I&M. This increase was partially offset in Gross Margin above.
- **Taxes Other Than Income Taxes** increased $20 million primarily due to the following:
  - A $12 million increase at SWEPCo primarily due to increased property taxes resulting from the expiration of the Louisiana Industrial Tax Exemption related to Stall Plant.
  - A $4 million increase at I&M primarily due to property taxes driven by an increase in utility plant.
- **Other Income** increased $8 million primarily due to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event.
- **Income Tax Expense** decreased $7 million primarily due to a decrease in state income tax expense and an increase in PTC. This decrease was partially offset by a decrease in amortization of Excess ADIT, a decrease in parent company loss benefit and an increase in pretax book income. The decrease in amortization of Excess ADIT is partially offset above in Retail Margins.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions)			
Revenues	$ 1,200.3	$ 1,165.3	$ 3,391.8	$ 3,306.7
Purchased Electricity	188.1	183.8	561.6	522.7
Gross Margin	1,012.2	981.5	2,830.2	2,784.0
Other Operation and Maintenance	442.6	439.1	1,168.6	1,158.2
Depreciation and Amortization	164.6	163.5	515.8	585.0
Taxes Other Than Income Taxes	167.5	156.4	483.5	444.4
Operating Income	237.5	222.5	662.3	596.4
Interest and Investment Income	0.4	0.9	1.1	2.0
Carrying Costs Income	0.1	0.3	1.1	1.3
Allowance for Equity Funds Used During Construction	11.3	9.0	24.3	23.7
Non-Service Cost Components of Net Periodic Benefit Cost	7.3	7.4	21.8	22.1
Interest Expense	(77.3)	(74.0)	(228.8)	(217.6)
Income Before Income Tax Expense	179.3	166.1	481.8	427.9
Income Tax Expense	23.4	18.7	57.8	24.8
Net Income	155.9	147.4	424.0	403.1
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 155.9	$ 147.4	$ 424.0	$ 403.1

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions of KWhs)			
Retail:				
Residential	8,093	8,277	21,082	20,876
Commercial	7,125	6,722	19,189	18,154
Industrial	6,048	5,417	17,667	16,473
Miscellaneous	207	206	558	568
Total Retail (a)	21,473	20,622	58,496	56,071
Wholesale (b)	644	502	1,692	1,347
Total KWhs	22,117	21,124	60,188	57,418

(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 September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in degree days)			
Eastern Region				
Actual – Heating (a)	1	2	1,993	1,767
Normal – Heating (b)	5	6	2,071	2,086
Actual – Cooling (c)	787	809	1,148	1,126
Normal – Cooling (b)	689	682	996	986
Western Region				
Actual – Heating (a)	—	1	319	98
Normal – Heating (b)	—	—	188	188
Actual – Cooling (d)	1,308	1,357	2,278	2,524
Normal – Cooling (b)	1,379	1,378	2,436	2,436

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2020	$	147.4
Changes in Gross Margin:		
Retail Margins		45.1
Margins from Off-system Sales		(31.1)
Transmission Revenues		27.4
Other Revenues		(10.7)
Total Change in Gross Margin		30.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(3.5)
Depreciation and Amortization		(1.1)
Taxes Other Than Income Taxes		(11.1)
Interest and Investment Income		(0.5)
Carrying Costs Income		(0.2)
Allowance for Equity Funds Used During Construction		2.3
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		(3.3)
Total Change in Expenses and Other		(17.5)
Income Tax Expense		(4.7)
Third Quarter of 2021	$	155.9

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

- **Retail Margins** increased $45 million primarily due to the following:
  - A $40 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $22 million increase due to prior year refunds in Texas of Excess ADIT and excess federal income taxes collected as a result of Tax Reform. This increase was partially offset in Income Tax Expense below.
  - A $15 million increase related to various rider revenues in Ohio. This increase was partially offset in Margins from Off-system Sales, Other Revenues and other expense items below.
  - A $13 million increase from interim rate increases driven by increased distribution investment in Texas.
  - A $3 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $3 million increase in usage in Ohio primarily from the industrial and commercial class.

  These increases were partially offset by:
  - A $24 million decrease due to the ending of the Energy Efficiency and Peak Demand Rider in Ohio in December 2020.This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $15 million decrease in revenues in Ohio associated with the Universal Service Fund (USF).This decrease was offset in Other Operation and Maintenance expenses below.
  - A $9 million decrease in weather-normalized margins in Texas primarily in the industrial class.
  - A $3 million decrease in weather-related usage in Texas primarily due to a 4% decrease in cooling degree days.
- **Margins from Off-system Sales** decreased $31 million primarily due to the following:
  - A $22 million decrease in Texas primarily due to the retirement of the Oklaunion Power Station in September 2020. This decrease was partially offset in Depreciation and Amortization expenses below.

    - A $19 million decrease in deferrals of OVEC costs in Ohio. This decrease was offset in Retail Margins above and Other Revenues below.

  These decreases were partially offset by:

    - A $10 million increase in off-system sales at OVEC in Ohio. This increase was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** increased $27 million primarily due to the following:
    - A $20 million increase from interim rate increases driven by increased transmission investment in Texas.
    - An $8 million increase due to prior year refunds to customers associated with the most recent base rate case in Texas. This increase was offset in Other Revenues below.
- **Other Revenues** decreased $11 million primarily due to the following:
    - A $10 million decrease in securitization revenues primarily due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Depreciation and Amortization expenses and Interest Expense below.
    - An $8 million decrease due to prior year refunds to customers associated with the most recent base rate case in Texas. This decrease was partially offset in Retail Margins and Transmission Revenues above.

  This decrease was partially offset by:

    - An $8 million increase primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs in Ohio. This increase was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $4 million primarily due to the following:
    - A $34 million increase in PJM transmission expenses. This increase was partially offset in Retail Margins above.
    - A $10 million increase in vegetation management expenses. This increase was partially offset in Retail Margins above.
    - A $10 million increase in distribution related expenses due to increased maintenance, storms and billings.
    - A $3 million increase due to timing of AEPSC taxes.

  These increases were partially offset by:

    - A $19 million decrease in Texas due to the Oklaunion Power Station retirement in September 2020 and its sale to a nonaffiliated third-party in October 2020. This decrease was offset in Gross Margin above.
    - A $16 million decrease in energy efficiency/demand side management expenses in Ohio. This decrease was partially offset in Retail Margins above.
    - A $15 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset in Retail Margins above.
    - A $6 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses increased $1 million primarily due to the following:
    - A $10 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.

  This increase was partially offset by:

    - A $9 million decrease in securitization amortizations in Texas primarily related to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Other Revenues above.
- **Taxes Other Than Income Taxes** increased $11 million primarily due to increased property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** increased $3 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $5 million primarily due to a decrease in amortization of Excess ADIT. This increase was partially offset in Gross Margin above.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2020	$	403.1
Changes in Gross Margin:		
Retail Margins		146.3
Margins from Off-system Sales		(87.2)
Transmission Revenues		69.9
Other Revenues		(82.8)
Total Change in Gross Margin		46.2
Changes in Expenses and Other:		
Other Operation and Maintenance		(10.4)
Depreciation and Amortization		69.2
Taxes Other Than Income Taxes		(39.1)
Interest and Investment Income		(0.9)
Carrying Costs Income		(0.2)
Allowance for Equity Funds Used During Construction		0.6
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(11.2)
Total Change in Expenses and Other		7.7
Income Tax Expense		(33.0)
Nine Months Ended September 30, 2021	$	424.0

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

- **Retail Margins** increased $146 million primarily due to the following:
  - A $129 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $71 million increase related to various rider revenues in Ohio. This increase was partially offset in Margins from Off-system Sales, Other Revenues and other expense items below.
  - A $34 million increase from interim rate increases driven by increased distribution investment in Texas.
  - An $18 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $10 million increase in weather-related usage in Texas primarily due to a 226% increase in heating degree days, partially offset by a 10% decrease in cooling degree days.

  These increases were partially offset by:
  - A $71 million decrease due to the ending of the Energy Efficiency and Peak Demand Rider in Ohio in December 2020.This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $43 million decrease in revenues in Ohio associated with the USF. This decrease was offset in Other Operation and Maintenance expenses below.
  - An $8 million decrease in weather-normalized margins in Texas primarily in the industrial class.
- **Margins from Off-system Sales** decreased $87 million primarily due to the following:
  - A $51 million decrease in Texas primarily due to the retirement of the Oklaunion Power Station in September 2020. This decrease was partially offset in Depreciation and Amortization expenses below.

- A $51 million decrease in deferrals of OVEC costs in Ohio. This decrease was offset in Retail Margins above and Other Revenues below.

These decreases were partially offset by:

- A $16 million increase in off-system sales at OVEC in Ohio. This increase was offset in Retail Margins above and Other Revenues below.

- **Transmission Revenues** increased $70 million primarily due to the following:
  - A $59 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $14 million increase due to a prior year one-time credit to transmission customers in Texas as a result of Tax Reform and the most recent base rate case. This increase was offset in Income Tax Expense below.
- **Other Revenues** decreased $83 million primarily due to the following:
  - A $104 million decrease in securitization revenues primarily due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Depreciation and Amortization expenses and Interest Expense below.

  This decrease was partially offset by:
  - A $21 million increase in Ohio primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $10 million primarily due to the following:
  - A $131 million increase in PJM transmission expenses including the annual formula rate true-up. This increase was partially offset in Retail Margins above.
  - A $16 million increase in vegetation management expenses. This increase was offset in Retail Margins above.
  - An $11 million increase in distribution related expenses.
  - A $7 million increase in storm expenses.

  These increases were partially offset by:
  - A $47 million decrease in energy efficiency/demand side management expenses in Ohio. This decrease was partially offset in Retail Margins above.
  - A $43 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset in Retail Margins above.
  - A $41 million decrease in Texas due to the Oklaunion Power Station retirement in September 2020 and its sale to a nonaffiliated third-party in October 2020. This decrease was offset in Gross Margin above.
  - A $19 million decrease in factored customer accounts receivable expenses primarily due to bad debt expenses and a current year adjustment to allowance for doubtful accounts.
  - A $5 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses decreased $69 million primarily due to the following:
  - A $102 million decrease in securitization amortizations in Texas primarily related to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Other Revenues above.

  These decreases were partially offset by:
  - An $18 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - An $8 million increase in amortization of plant primarily related to capitalized software in Ohio.
  - A $7 million increase in recoverable DIR depreciable expense in Ohio. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $39 million primarily due to property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** increased $11 million primarily due to higher long-term debt balances.

- **Income Tax Expense** increased $33 million primarily due to a decrease in amortization of Excess ADIT and an increase in pretax book income, partially offset by favorable discrete adjustments recognized during the periods. The decrease in amortization of Excess ADIT is partially offset in Gross Margin above.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions)			
Transmission Revenues	$ 391.6	$ 317.9	$ 1,146.8	$ 877.8
Other Operation and Maintenance	40.3	30.1	96.9	85.9
Depreciation and Amortization	78.1	63.6	225.5	182.8
Taxes Other Than Income Taxes	62.7	53.8	183.4	157.5
Operating Income	210.5	170.4	641.0	451.6
Interest and Investment Income	0.3	0.2	0.7	2.6
Allowance for Equity Funds Used During Construction	16.1	20.3	49.3	54.9
Non-Service Cost Components of Net Periodic Benefit Cost	0.5	0.5	1.6	1.5
Interest Expense	(37.6)	(34.0)	(108.4)	(99.0)
Income Before Income Tax Expense and Equity Earnings	189.8	157.4	584.2	411.6
Income Tax Expense	42.0	38.2	131.2	101.3
Equity Earnings of Unconsolidated Subsidiary	20.1	20.1	57.7	62.8
Net Income	167.9	139.3	510.7	373.1
Net Income Attributable to Noncontrolling Interests	1.1	1.0	3.2	2.7
Earnings Attributable to AEP Common Shareholders	$ 166.8	$ 138.3	$ 507.5	$ 370.4

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2021	September 30, 2020
	(in millions)	
Plant in Service	$ 11,256.0	$ 9,644.6
Construction Work in Progress	1,609.6	1,732.5
Accumulated Depreciation and Amortization	758.1	553.1
Total Transmission Property, Net	$ 12,107.5	$ 10,824.0

Third Quarter of 2021 Compared to Third Quarter of 2020

Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2020	$	138.3
Changes in Transmission Revenues:		
Transmission Revenues		73.7
Total Change in Transmission Revenues		73.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(10.2)
Depreciation and Amortization		(14.5)
Taxes Other Than Income Taxes		(8.9)
Interest Income		0.1
Allowance for Equity Funds Used During Construction		(4.2)
Interest Expense		(3.6)
Total Change in Expenses and Other		(41.3)
Income Tax Expense		(3.8)
Net Income Attributable to Noncontrolling Interests		(0.1)
Third Quarter of 2021	$	166.8

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

- **Transmission Revenues** increased $74 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $10 million primarily due to the following:
  - A $2 million increase in vegetation management expenses.
  - A $2 million increase in an accrual for NERC compliance costs.
  - A $2 million increase in employee-related expenses.
  - A $1 million increase in rent expense.
- **Depreciation and Amortization** expenses increased $15 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** decreased $4 million primarily due to lower CWIP.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $4 million primarily due to an increase in pretax book income, partially offset by an increase in parent company loss benefit.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2020	$	370.4
Changes in Transmission Revenues:		
Transmission Revenues		269.0
Total Change in Transmission Revenues		269.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(11.0)
Depreciation and Amortization		(42.7)
Taxes Other Than Income Taxes		(25.9)
Interest Income		(1.9)
Allowance for Equity Funds Used During Construction		(5.6)
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(9.4)
Total Change in Expenses and Other		(96.4)
Income Tax Expense		(29.9)
Equity Earnings of Unconsolidated Subsidiary		(5.1)
Net Income Attributable to Noncontrolling Interests		(0.5)
Nine Months Ended September 30, 2021	$	507.5

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

- **Transmission Revenues** increased $269 million primarily due to the following:
  - A $206 million increase due to continued investment in transmission assets.
  - A $45 million increase as a result of the affiliated annual transmission formula rate true-up which is offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $16 million increase as a result of the non-affiliated annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses increased $11 million primarily due to the following:
  - A $4 million increase in vegetation management expenses.
  - A $2 million increase in an accrual for NERC compliance costs.
  - A $2 million increase in rent expense.
  - A $1 million increase in property insurance premiums.
- **Depreciation and Amortization** expenses increased $43 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $26 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $6 million primarily due to lower CWIP.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $30 million primarily due to an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiary** decreased $5 million primarily due to lower pretax equity earnings at PATH-WV and ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2021	2020	Nine Months Ended September 30, 2021	2020
	(in millions)			
Revenues	$ 621.1	$ 490.0	$ 1,691.9	$ 1,305.5
Fuel, Purchased Electricity and Other	444.7	391.6	1,368.7	1,050.4
Gross Margin	176.4	98.4	323.2	255.1
Other Operation and Maintenance	38.2	27.2	98.8	85.1
Depreciation and Amortization	21.1	18.5	59.7	54.1
Taxes Other Than Income Taxes	2.6	3.3	8.1	10.4
Operating Income	114.5	49.4	156.6	105.5
Interest and Investment Income	1.3	0.4	2.4	2.6
Non-Service Cost Components of Net Periodic Benefit Cost	3.8	3.9	11.5	11.6
Interest Expense	(4.0)	(3.8)	(11.1)	(20.5)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	115.6	49.9	159.4	99.2
Income Tax Expense (Benefit)	8.3	(70.9)	(31.0)	(104.3)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(7.8)	(6.2)	(6.2)	0.1
Net Income	99.5	114.6	184.2	203.6
Net Loss Attributable to Noncontrolling Interests	(1.2)	(2.1)	(5.5)	(7.4)
Earnings Attributable to AEP Common Shareholders	$ 100.7	$ 116.7	$ 189.7	$ 211.0

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2021	2020	Nine Months Ended September 30, 2021	2020
	(in millions of MWhs)			
Fuel Type:				
Coal	1	1	3	3
Renewables	1	—	3	2
Total MWhs	2	1	6	5

Third Quarter of 2021 Compared to Third Quarter of 2020

Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2020	$	116.7
Changes in Gross Margin:		
Merchant Generation		(2.5)
Renewable Generation		8.9
Retail, Trading and Marketing		71.6
Total Change in Gross Margin		78.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(11.0)
Depreciation and Amortization		(2.6)
Taxes Other Than Income Taxes		0.7
Interest and Investment Income		0.9
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		(0.2)
Total Change in Expenses and Other		(12.3)
Income Tax Expense		(79.2)
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(1.6)
Net Loss Attributable to Noncontrolling Interests		(0.9)
Third Quarter of 2021	$	100.7

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

- **Merchant Generation** decreased $3 million primarily due to the retirement of Oklaunion Plant in 2020.
- **Renewable Generation** increased $9 million primarily due to higher solar and wind production.
- **Retail, Trading and Marketing** increased $72 million due to higher mark-to-market hedge gains driven by higher commodity prices.

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

- **Other Operation and Maintenance** expenses increased $11 million primarily due to the following:
  - An $18 million increase due to gains recorded in 2020 on the sale of land.

  This increase was partially offset by:
  - A $7 million decrease in expenses related to the installment sale of Amazon substations and the retirement of Oklaunion Plant in 2020.
- **Income Tax Expense** increased $79 million primarily due to the recognition of a discrete tax adjustment in 2020 attributable to the CARES Act, the impact of PTCs on the annualized effective tax rate and an increase in pretax book income.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2020	$	211.0
Changes in Gross Margin:		
Merchant Generation		6.6
Renewable Generation		17.2
Retail, Trading and Marketing		44.3
Total Change in Gross Margin		68.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(13.7)
Depreciation and Amortization		(5.6)
Taxes Other Than Income Taxes		2.3
Interest and Investment Income		(0.2)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		9.4
Total Change in Expenses and Other		(7.9)
Income Tax Benefit		(73.3)
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(6.3)
Net Loss Attributable to Noncontrolling Interests		(1.9)
Nine Months Ended September 30, 2021	$	189.7

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

- **Merchant Generation** increased $7 million primarily due to higher market prices in PJM which drove increased generation at Cardinal Plant.
- **Renewable Generation** increased $17 million primarily due to increased solar and wind production.
- **Retail, Trading and Marketing** increased $44 million due to higher mark-to-market hedge gains driven by higher commodity prices. This increase was partially offset by lower trading and retail margins due to unprecedented cold temperatures and record ERCOT market prices in February 2021.

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

- **Other Operation and Maintenance** expenses increased $14 million primarily due to the following:
  - A $20 million increase from gains recorded in 2020 on the sale of land.
  - A $17 million increase related to the Oklaunion PPA with AEP Texas primarily due to an ARO revision in 2020.

  These increases were partially offset by:
  - A $10 million decrease due to the retirement of Conesville Plant Unit 4 in 2020.
  - A $5 million decrease due to a planned outage at Cardinal Plant in 2020.
  - A $4 million decrease due to the retirement of Oklaunion Plant in 2020.
  - A $4 million decrease due to the installment sale of Amazon substations.
- **Depreciation and Amortization** expenses increased $6 million due to a higher depreciable base from increased investments in renewable energy sources.

- **Interest Expense** decreased $9 million due to lower borrowing costs in 2021.
- **Income Tax Benefit** decreased $73 million primarily due to the recognition of a discrete tax adjustment in 2020 attributable to the CARES Act, the impact of PTCs on the annualized effective tax rate and an increase in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $6 million primarily due to lower revenues due to lower wind production from jointly owned assets.

CORPORATE AND OTHER

Third Quarter of 2021 Compared to Third Quarter of 2020

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $47 million in 2020 to a loss of $65 million in 2021 primarily due to:

- A $26 million unrealized loss from an investment in ChargePoint.
- A $6 million decrease in interest income due to a lower return on investments held by EIS and lower interest income from affiliates.

These items were partially offset by:

- A $9 million decrease in Income Tax Expense due to lower pretax book income and a decrease in the consolidated tax adjustment.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $115 million in 2020 to a loss of $108 million in 2021 primarily due to:

- A $23 million increase in equity earnings from unrealized investment gains.
- A $16 million decrease in interest expense.
- A $12 million gain from an investment in ChargePoint, of which $7 million is unrealized.

These items were partially offset by:

- A $21 million decrease in interest income primarily due to lower interest income from affiliates.
- A $12 million increase in the EIS reserve.
- An $8 million increase in general corporate expenses.
- A $6 million increase in estimated health care benefits for certain retirees.

AEP SYSTEM INCOME TAXES

Third Quarter of 2021 Compared to Third Quarter of 2020

Income Tax Expense increased $71 million primarily due to the following:

- A $52 million increase due to the recognition of a discrete tax adjustment in 2020 attributable to the CARES Act.
- A $25 million increase due to an increase in pretax book income.
- An $8 million increase due to a decrease in amortization of Excess ADIT.

These increases were partially offset by:

- A $15 million decrease in state income tax expense.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Income Tax Expense increased $128 million primarily due to the following:

- A $66 million increase due to an increase in pretax book income.
- A $52 million increase due to the recognition of a discrete tax adjustment in 2020 attributable to the CARES Act.
- A $19 million increase due to the remeasurement of deferred state income taxes as a result of legislative changes in 2021.

These increases were partially offset by:

- A $23 million increase in PTC.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2021		December 31, 2020	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 34,578.3	58.0 %	$ 31,072.5	57.2 %
Short-term Debt	2,504.0	4.2	2,479.3	4.6
Total Debt	37,082.3	62.2	33,551.8	61.8
AEP Common Equity	22,278.1	37.4	20,550.9	37.8
Noncontrolling Interests	249.1	0.4	223.6	0.4
Total Debt and Equity Capitalization	$ 59,609.5	100.0 %	$ 54,326.3	100.0 %

AEP's ratio of debt-to-total capital increased from 61.8% as of December 31, 2020 to 62.2% as of September 30, 2021 primarily due to an increase in debt to help address the cash flow implications resulting from the February 2021 severe winter weather event in addition to supporting distribution, transmission and renewable investment growth.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of September 30, 2021, AEP had $5 billion of revolving credit facilities 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. In February 2021, severe winter weather impacted certain AEP service territories resulting in disruptions to SPP market conditions.In March 2021, AEP entered into a $500 million 364-day Term Loan and borrowed the full amount to help address the cash flow implications resulting from the February 2021 severe winter weather event. See Note 4 - Rate Matters for additional information.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2021, available liquidity was approximately $5.1 billion as illustrated in the table below:

		Amount	Maturity
Commercial Paper Backup:		(in millions)	
	Revolving Credit Facility	$ 4,000.0	March 2026
	Revolving Credit Facility	1,000.0	March 2023
	364-Day Term Loan	500.0	March 2022
Cash and Cash Equivalents		1,372.7	
Total Liquidity Sources		6,872.7	
Less:	AEP Commercial Paper Outstanding	1,254.0	
	364-Day Term Loan	500.0	
Net Available Liquidity		$ 5,118.7	

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 nine months of 2021 was $2.5 billion. The weighted-average interest rate for AEP's commercial paper during 2021 was 0.24%.

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 five uncommitted facilities totaling $375 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2021 was $180 million with maturities ranging from October 2021 to August 2022.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility which expire in September 2023 and 2024, respectively. As of September 30, 2021, the affiliated utility subsidiaries are in compliance with all requirements under the agreement.

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 September 30, 2021, this contractually-defined percentage was 59.3%. 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 facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

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

At-the-Market (ATM) Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, up to an aggregate of $1 billion of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. As of September 30, 2021, approximately $534 million of equity is available for issuance under the ATM offering program. See Note 12 - Financing Activities for additional information.

Equity Units

In August 2020, AEP issued 17 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $850 million. Net proceeds from the issuance were approximately $833 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes due in 2025 and a forward equity purchase contract which settles after three years in 2023. The proceeds were used to support AEP's overall capital expenditure plans.

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 $0.78 per share in October 2021, a $0.04 per share increase as compared to the quarterly dividend declared in July 2021. 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.

	Nine Months Ended September 30,	
	2021	2020
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 438.3	$ 432.6
Net Cash Flows from Operating Activities	2,973.0	2,922.2
Net Cash Flows Used for Investing Activities	(4,906.2)	(4,707.3)
Net Cash Flows from Financing Activities	2,921.6	1,816.3
Net Increase in Cash and Cash Equivalents	988.4	31.2
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 1,426.7	$ 463.8

Operating Activities

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions)	
Net Income	$ 1,949.5	$ 1,762.0
Non-Cash Adjustments to Net Income (a)	2,353.8	2,196.7
Mark-to-Market of Risk Management Contracts	101.0	46.4
Pension Contributions to Qualified Plan Trust	—	(110.3)
Property Taxes	415.1	396.9
Deferred Fuel Over/Under-Recovery, Net	(1,356.8)	27.4
Change in Other Noncurrent Assets	(270.7)	(322.0)
Change in Other Noncurrent Liabilities	162.7	(25.1)
Change in Certain Components of Working Capital	(381.6)	(1,049.8)
Net Cash Flows from Operating Activities	$ 2,973.0	$ 2,922.2

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Rockport Plant, Unit 2 Operating Lease Amortization, Deferred Income Taxes, AFUDC and Amortization of Nuclear Fuel.

Net Cash Flows from Operating Activities increased by $51 million primarily due to the following:

- A $668 million increase in cash from the Change in Certain Components of Working Capital. The increase is primarily due to timing of accounts receivables and payables and a decrease in fuel, material and supplies balances primarily due to decreases in coal and lignite inventory on hand.
- A $345 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $188 million increase in cash from Change in Other Noncurrent Liabilities. The increase is primarily due to changes in regulatory liabilities driven by timing differences between collections from and refunds to customers under rate rider mechanisms.
- A $110 million increase in cash due to a discretionary contribution to the qualified pension plan made in the prior year. See Note 7 for additional information.

These increases in cash were partially offset by:

- A $1.4 billion decrease in cash primarily due to fuel and purchased power expenses incurred as a result of the February 2021 severe winter weather event in SPP impacting PSO and SWEPCo. Approximately $1.1 billion of these expenses are attributable to retail customers and are recorded as deferred fuel regulatory assets. PSO and SWEPCo are working with their respective regulatory commissions to determine the recovery period from customers as well as the appropriate carrying charge on the regulatory assets. See Note 4 - Rate Matters for additional information.
- A $142 million decrease in cash due to incremental other operation and maintenance storm restoration expenses incurred by APCo, SWEPCo and KPCo as a result of the February 2021 severe winter weather event. These incremental expenses have been deferred as regulatory assets. KPCo intends to seek recovery of these incremental storm restoration costs in their next base rate case while APCo is expected to seek recovery in separate filings. In October 2021, SWEPCo requested recovery of these storm costs, in addition to storm costs from Hurricanes Delta and Laura, in a filing with the LPSC. See Note 4 - Rate Matters for additional information.

Investing Activities

	Nine Months Ended September 30,			
	2021		2020	
	(in millions)			
Construction Expenditures	$	(4,087.0)	$	(4,690.4)
Acquisitions of Nuclear Fuel		(63.2)		(68.4)
Acquisition of the North Central Wind Energy Facilities		(652.8)		—
Acquisition of the Dry Lake Solar Project		(114.4)		—
Other		11.2		51.5
Net Cash Flows Used for Investing Activities	$	(4,906.2)	$	(4,707.3)

Net Cash Flows Used for Investing Activities increased by $199 million primarily due to the following:

- A $767 million increase due to the acquisition of the North Central Wind Energy Facilities and the Dry Lake Solar ProjectSee Note 6 - Acquisitions and Dispositions for additional information.

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

- A $603 million decrease in construction expenditures, primarily due to decreases in Transmission and Distribution Utilities of $302 million, Vertically Integrated Utilities of $136 million and AEP Transmission Holdco of $76 million.

Financing Activities

	Nine Months Ended September 30,			
	2021		2020	
	(in millions)			
Issuance of Common Stock	$	548.0	$	136.5
Issuance/Retirement of Debt, Net		3,537.2		2,844.0
Dividends Paid on Common Stock		(1,122.7)		(1,055.7)
Other		(40.9)		(108.5)
Net Cash Flows from Financing Activities	$	2,921.6	$	1,816.3

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

- A $1.1 billion increase in issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $466 million increase due to changes in short-term debt. See Note 12 - Financing Activities for additional information.
- A $412 million increase in issuances of common stock primarily due to AEP's participation in an At-the-Market offering program. See Note 12 - Financing Activities for additional information.

These increases in cash were partially offset by:

- An $849 million increase in 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 September 30, 2021 through October 28, 2021, the date that the third quarter 10-Q was issued.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $6.9 billion of capital expenditures in 2021. For the four year period, 2022 through 2025, management forecasts capital expenditures of $30.4 billion. The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. 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 2020 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2020 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 2020 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.There are no new standards expected to have a material impact to the Registrants' financial statements.

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, Chief Operating Officer, Executive Vice President of Generation, Senior Vice President of Grid Solutions, 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 Senior 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 continue to be monitored, and while markets have shown improvement, credit risks remain as counterparties encounter business and supply chain disruptions.

Due to multiple defaults of market participants, ERCOT has a large outstanding unpaid balance associated with the February storm.Socialized losses are allocated to load serving entities through their qualified scheduling entities and in that role AEPEP is exposed, but not materially. If the market rules were to change on how socialized losses are allocated this could affect AEPEP's exposure. Regardless of the approach of how socialized losses are allocated there are potential downstream impacts that could push counterparties into financial distress and or bankruptcy, affecting AEPEP, AEP Texas and ETT.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2020:

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2021

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2020	$ 41.2	$ (109.5)	$ 168.1	$ 99.8
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(20.4)	(5.6)	(11.9)	(37.9)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	1.0	1.0
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	138.1	138.1
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	46.3	26.4	—	72.7
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2021	$ 67.1	$ (88.7)	$ 295.3	273.7
Commodity Cash Flow Hedge Contracts				359.5
Interest Rate Cash Flow Hedge Contracts				4.9
Fair Value Hedge Contracts				(25.4)
Collateral Deposits				(271.3)
Total MTM Derivative Contract Net Assets as of September 30, 2021				$ 341.4

(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 September 30, 2021, credit exposure net of collateral to sub investment grade counterparties was approximately 1.8%, 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 September 30, 2021, 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	$ 505.7	$ 33.6	$ 472.1	3	$ 199.3
No External Ratings:					
Internal Investment Grade	80.4	—	80.4	3	61.9
Internal Noninvestment Grade	14.2	4.2	10.0	2	5.8
Total as of September 30, 2021	$ 600.3	$ 37.8	$ 562.5		

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 September 30, 2021, 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

Nine Months Ended September 30, 2021				Twelve Months Ended December 31, 2020			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 1.7	$ 3.6	$ 0.3	$ 0.1	$ 0.1	$ 0.3	$ 0.1	$ —

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2021				Twelve Months Ended December 31, 2020			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 7.7	$ 7.8	$ 2.3	$ 0.7	$ 2.2	$ 2.9	$ 1.0	$ 0.1

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 nine months ended September 30, 2021 and 2020, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $32 million and $18 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
REVENUES				
Vertically Integrated Utilities	$ 2,716.8	$ 2,400.1	$ 7,445.9	$ 6,655.4
Transmission and Distribution Utilities	1,195.0	1,124.1	3,366.9	3,208.7
Generation & Marketing	617.4	464.8	1,641.6	1,223.4
Other Revenues	93.8	77.4	276.2	220.4
TOTAL REVENUES	4,623.0	4,066.4	12,730.6	11,307.9
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,441.4	1,200.4	4,126.1	3,316.3
Other Operation	735.3	702.9	1,894.6	1,871.0
Maintenance	277.8	237.6	817.0	730.5
Depreciation and Amortization	700.3	644.6	2,103.9	1,996.3
Taxes Other Than Income Taxes	360.8	337.7	1,061.4	976.3
TOTAL EXPENSES	3,515.6	3,123.2	10,003.0	8,890.4
OPERATING INCOME	1,107.4	943.2	2,727.6	2,417.5
Other Income (Expense):				
Other Income (Expense)	(20.6)	5.5	34.2	15.4
Allowance for Equity Funds Used During Construction	37.0	45.2	103.9	111.7
Non-Service Cost Components of Net Periodic Benefit Cost	29.6	29.7	88.9	89.2
Interest Expense	(303.7)	(291.3)	(895.5)	(877.4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	849.7	732.3	2,059.1	1,756.4
Income Tax Expense (Benefit)	69.8	(1.2)	185.5	57.9
Equity Earnings of Unconsolidated Subsidiaries	17.0	14.7	75.9	63.5
NET INCOME	796.9	748.2	1,949.5	1,762.0
Net Income (Loss) Attributable to Noncontrolling Interests	0.9	(0.4)	0.3	(2.6)
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 796.0	$ 748.6	$ 1,949.2	$ 1,764.6
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	501,233,680	496,177,968	499,418,278	495,479,190
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.59	$ 1.51	$ 3.90	$ 3.56
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	502,606,836	497,458,523	500,600,237	496,916,187
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.58	$ 1.50	$ 3.89	$ 3.55

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
et Income	$ 796.9	$ 748.2	$ 1,949.5	$ 1,762.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $47.8 and $10.5 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $97.3 and $4.7 for the Nine Months Ended September 30, 2021 and 2020, Respectively	179.7	39.3	365.9	17.6
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.5) and $(0.5) for the Three Months Ended September 30, 2021 and 2020, Respectively, and $(1.6) and $(1.4) for the Nine Months Ended September 30, 2021 and 2020, Respectively	(2.0)	(1.8)	(6.1)	(5.3)
OTAL OTHER COMPREHENSIVE INCOME	177.7	37.5	359.8	12.3
OTAL COMPREHENSIVE INCOME	974.6	785.7	2,309.3	1,774.3
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	0.9	(0.4)	0.3	(2.6)
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 973.7	$ 786.1	$ 2,309.0	$ 1,776.9

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
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) (a)		(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
Issuance of Common Stock	0.8	5.2	49.7				54.9
Common Stock Dividends				(337.7) (a)		(3.2)	(340.9)
Other Changes in Equity			(2.6)			1.0	(1.6)
Net Income (Loss)				520.8		(6.3)	514.5
Other Comprehensive Income					43.6		43.6
TOTAL EQUITY – JUNE 30, 2020	516.2	3,355.4	6,603.0	10,221.9	(172.9)	270.8	20,278.2
Issuance of Common Stock	0.4	2.2	23.3				25.5
Common Stock Dividends				(349.1) (a)		(2.0)	(351.1)
Other Changes in Equity			(104.0) (b)			0.3	(103.7)
Net Income (Loss)				748.6		(0.4)	748.2
Other Comprehensive Income					37.5		37.5
TOTAL EQUITY – SEPTEMBER 30, 2020	516.6	$ 3,357.6	$ 6,522.3	$ 10,621.4	$ (135.4)	$ 268.7	$ 20,634.6
TOTAL EQUITY – DECEMBER 31, 2020	516.8	$ 3,359.3	$ 6,588.9	$ 10,687.8	$ (85.1)	$ 223.6	$ 20,774.5
Issuance of Common Stock	2.7	17.1	167.5				184.6
Common Stock Dividends				(369.5) (c)		(2.5)	(372.0)
Other Changes in Equity			(21.9)	(0.6)		3.4	(19.1)
Acquisition of Dry Lake Solar Project						18.9	18.9
Net Income				575.0		3.8	578.8
Other Comprehensive Income					54.3		54.3
TOTAL EQUITY – MARCH 31, 2021	519.5	3,376.4	6,734.5	10,892.7	(30.8)	247.2	21,220.0
Issuance of Common Stock	0.9	6.3	66.0				72.3
Common Stock Dividends				(371.8) (c)		(2.7)	(374.5)
Other Changes in Equity			(0.2)	(0.4)		11.1	10.5
Net Income (Loss)				578.2		(4.4)	573.8
Other Comprehensive Income					127.8		127.8
TOTAL EQUITY – JUNE 30, 2021	520.4	3,382.7	6,800.3	11,098.7	97.0	251.2	21,629.9
Issuance of Common Stock	3.4	21.8	269.3				291.1
Common Stock Dividends				(371.7) (c)		(4.5)	(376.2)
Other Changes in Equity			6.3			1.5	7.8
Net Income				796.0		0.9	796.9
Other Comprehensive Income					177.7		177.7
TOTAL EQUITY – SEPTEMBER 30, 2021	523.8	$ 3,404.5	$ 7,075.9	$ 11,523.0	$ 274.7	$ 249.1	$ 22,527.2

(a) Cash dividends declared per AEP common share were $0.70.
(b) Includes $(121) million related to a forward equity purchase contract associated with the issuance of Equity Units.
(c) Cash dividends declared per AEP common share were $0.74.

ondensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

		September 30, 2021		December 31, 2020
CURRENT ASSETS				
Cash and Cash Equivalents	$	1,372.7	$	392.7
Restricted Cash (September 30, 2021 and December 31, 2020 Amounts Include $54 and $45.6, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)		54.0		45.6
Other Temporary Investments (September 30, 2021 and December 31, 2020 Amounts Include $211.5 and $194.6, Respectively, Related to EIS and Transource Energy)		218.4		200.8
Accounts Receivable:				
Customers		701.2		613.6
Accrued Unbilled Revenues		279.3		248.7
Pledged Accounts Receivable – AEP Credit		1,071.1		1,018.4
Miscellaneous		50.5		33.1
Allowance for Uncollectible Accounts		(51.7)		(71.1)
Total Accounts Receivable		2,050.4		1,842.7
Fuel		290.1		629.4
Materials and Supplies		688.4		680.6
Risk Management Assets		369.2		94.7
Accrued Tax Benefits		226.6		185.3
Regulatory Asset for Under-Recovered Fuel Costs		307.0		90.7
Margin Deposits		73.2		62.0
Prepayments and Other Current Assets		135.1		127.0
TOTAL CURRENT ASSETS		5,785.1		4,351.5
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Generation		24,135.9		23,133.9
Transmission		29,555.1		27,886.7
Distribution		25,057.7		23,972.1
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)		5,668.5		5,294.6
Construction Work in Progress		4,151.0		4,025.7
Total Property, Plant and Equipment		88,568.2		84,313.0
Accumulated Depreciation and Amortization		21,877.0		20,411.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET		66,691.2		63,901.6
OTHER NONCURRENT ASSETS				
Regulatory Assets		5,031.5		3,527.0
Securitized Assets		580.4		657.0
Spent Nuclear Fuel and Decommissioning Trusts		3,609.8		3,306.7
Goodwill		52.5		52.5
Long-term Risk Management Assets		278.3		242.2
Operating Lease Assets		779.8		866.4
Deferred Charges and Other Noncurrent Assets		3,528.5		3,852.3
TOTAL OTHER NONCURRENT ASSETS		13,860.8		12,504.1
TOTAL ASSETS	$	86,337.1	$	80,757.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2021 and December 31, 2020
(in millions, except per-share and share amounts)
(Unaudited)

			September 30, 2021	December 31, 2020
CURRENT LIABILITIES				
Accounts Payable			$ 1,597.1	$ 1,709.7
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit			750.0	592.0
Other Short-term Debt			1,754.0	1,887.3
Total Short-term Debt			2,504.0	2,479.3
Long-term Debt Due Within One Year (September 30, 2021 and December 31, 2020 Amounts Include $203.2 and $198.3, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			2,521.8	2,086.1
Risk Management Liabilities			106.5	78.8
Customer Deposits			400.2	335.6
Accrued Taxes			1,046.6	1,476.4
Accrued Interest			349.7	267.6
Obligations Under Operating Leases			241.8	241.3
Regulatory Liability for Over-Recovered Fuel Costs			3.5	52.6
Other Current Liabilities			1,182.8	1,199.3
TOTAL CURRENT LIABILITIES			9,954.0	9,926.7
NONCURRENT LIABILITIES				
Long-term Debt (September 30, 2021 and December 31, 2020 Amounts Include $887 and $950.1, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			32,056.5	28,986.4
Long-term Risk Management Liabilities			199.6	232.8
Deferred Income Taxes			8,644.8	8,240.9
Regulatory Liabilities and Deferred Investment Tax Credits			8,687.8	8,378.7
Asset Retirement Obligations			2,612.0	2,469.2
Employee Benefits and Pension Obligations			322.2	336.4
Obligations Under Operating Leases			586.8	638.4
Deferred Credits and Other Noncurrent Liabilities			672.9	728.0
TOTAL NONCURRENT LIABILITIES			53,782.6	50,010.8
TOTAL LIABILITIES			63,736.6	59,937.5
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards			73.3	45.2
TOTAL MEZZANINE EQUITY			73.3	45.2
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2021	**2020**		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	523,773,631	516,808,354		
(20,204,160 Shares were Held in Treasury as of September 30, 2021 and December 31, 2020, Respectively)			3,404.5	3,359.3
Paid-in Capital			7,075.9	6,588.9
Retained Earnings			11,523.0	10,687.8
Accumulated Other Comprehensive Income (Loss)			274.7	(85.1)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			22,278.1	20,550.9
Noncontrolling Interests			249.1	223.6
TOTAL EQUITY			22,527.2	20,774.5
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$ 86,337.1	$ 80,757.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
OPERATING ACTIVITIES		
Net Income	$ 1,949.5	$ 1,762.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	2,103.9	1,996.3
Rockport Rent, Unit 2 Operating Lease Amortization	100.8	102.4
Deferred Income Taxes	191.1	142.5
Allowance for Equity Funds Used During Construction	(103.9)	(111.7)
Mark-to-Market of Risk Management Contracts	101.0	46.4
Amortization of Nuclear Fuel	61.9	67.2
Pension Contributions to Qualified Plan Trust	—	(110.3)
Property Taxes	415.1	396.9
Deferred Fuel Over/Under-Recovery, Net	(1,356.8)	27.4
Change in Other Noncurrent Assets	(270.7)	(322.0)
Change in Other Noncurrent Liabilities	162.7	(25.1)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(199.2)	(138.9)
Fuel, Materials and Supplies	347.4	(97.4)
Accounts Payable	107.6	21.9
Accrued Taxes, Net	(471.1)	(502.9)
Rockport Plant, Unit 2 Operating Lease Payments	(73.9)	(73.9)
Other Current Assets	(33.3)	26.0
Other Current Liabilities	(59.1)	(284.6)
Net Cash Flows from Operating Activities	2,973.0	2,922.2
INVESTING ACTIVITIES		
Construction Expenditures	(4,087.0)	(4,690.4)
Purchases of Investment Securities	(1,612.3)	(1,329.5)
Sales of Investment Securities	1,571.7	1,293.0
Acquisitions of Nuclear Fuel	(63.2)	(68.4)
Acquisition of the Dry Lake Solar Project	(114.4)	—
Acquisition of the North Central Wind Energy Facilities	(652.8)	—
Other Investing Activities	51.8	88.0
Net Cash Flows Used for Investing Activities	(4,906.2)	(4,707.3)
FINANCING ACTIVITIES		
Issuance of Common Stock	548.0	136.5
Issuance of Long-term Debt	5,062.3	3,985.8
Issuance of Short-term Debt with Original Maturities greater than 90 Days	1,178.5	1,304.5
Change in Short-term Debt with Original Maturities less than 90 Days, Net	(632.5)	(1,445.8)
Retirement of Long-term Debt	(1,549.8)	(700.5)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(521.3)	(300.0)
Principal Payments for Finance Lease Obligations	(45.3)	(46.3)
Dividends Paid on Common Stock	(1,122.7)	(1,055.7)
Redemption of Noncontrolling Interest in Trent and Desert Sky Windfarms	—	(56.5)
Other Financing Activities	4.4	(5.7)
Net Cash Flows from Financing Activities	2,921.6	1,816.3
Net Increase in Cash and Cash Equivalents	988.4	31.2
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	438.3	432.6
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 1,426.7	$ 463.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 775.2	$ 690.5
Net Cash Paid (Received) for Income Taxes	9.3	(23.9)
Noncash Acquisitions Under Finance Leases	23.0	33.0
Construction Expenditures Included in Current Liabilities as of September 30,	764.1	830.1
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	—	8.3
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.3	1.0
Noncash Contribution of Assets to Cedar Creek Project	(9.3)	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0.6	2.4
Noncontrolling Interest Assumed - Dry Lake Solar Project	35.0	—
Forward Equity Purchase Contract Included in Current and Noncurrent Liabilities as of September 30,	—	120.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TEXAS INC.
AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions of KWhs)			
Retail:				
Residential	3,997	4,112	9,821	9,736
Commercial	3,014	2,941	7,907	7,700
Industrial	2,414	2,037	6,898	6,618
Miscellaneous	182	184	478	486
Total Retail	9,607	9,274	25,104	24,540

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in degree days)			
Actual – Heating (a)	—	1	319	98
Normal – Heating (b)	—	—	188	188
Actual – Cooling (c)	1,308	1,357	2,278	2,524
Normal – Cooling (b)	1,379	1,378	2,436	2,436

(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 70 degree temperature base.

Third Quarter of 2021 Compared to Third Quarter of 2020

AEP Texas Inc. and Subsidiaries
Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Net Income
(in millions)

Third Quarter of 2020	$	82.6
Changes in Gross Margin:		
Retail Margins		29.8
Margins from Off-system Sales		(30.1)
Transmission Revenues		29.7
Other Revenues		(18.4)
Total Change in Gross Margin		11.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(2.6)
Depreciation and Amortization		20.1
Taxes Other Than Income Taxes		(2.9)
Interest Income		(0.3)
Allowance for Equity Funds Used During Construction		4.8
Interest Expense		0.3
Total Change in Expenses and Other		19.4
Income Tax Expense		(13.5)
Third Quarter of 2021	$	99.5

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

- **Retail Margins** increased $30 million primarily due to the following:
  - A $22 million increase due to prior year refunds of Excess ADIT and excess federal income taxes collected as a result of Tax Reform. This increase was partially offset in Income Tax Expense below.
  - A $13 million increase from interim rate increases driven by increased distribution investment.
  - A $3 million increase from interim rate increases driven by increased transmission investment.

  These increases were partially offset by:
  - A $9 million decrease in weather-normalized margins primarily in the industrial class.
  - A $3 million decrease in weather-related usage primarily due to a 4% decrease in cooling degree days.
- **Margins from Off-system Sales** decreased $30 million primarily due to the retirement of the Oklaunion Power Station in September 2020. This decrease was partially offset in Depreciation and Amortization expenses below.
- **Transmission Revenues** increased $30 million primarily due to the following:
  - A $20 million increase from interim rate increases driven by increased transmission investment.
  - An $8 million increase due to prior year refunds to customers associated with the most recent base rate case. This increase was offset in Other Revenues below.
- **Other Revenues** decreased $18 million primarily due to the following:
  - A $10 million decrease in securitization revenues primarily due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset below in Depreciation and Amortization expenses and in Interest Expense.
  - An $8 million decrease due to prior year refunds to customers associated with the most recent base rate case. This decrease was partially offset in Retail Margins and Transmission Revenues above.

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

- **Other Operation and Maintenance** expenses increased $3 million primarily due to the following:
  - A $5 million increase in transmission expenses. This increase was partially offset in Gross Margin above.
  - A $2 million increase in distribution-related expenses.

  These increases were partially offset by:
  - A $5 million decrease due to the prior year write-off of land associated with the Oklaunion Power Station.
- **Depreciation and Amortization** expenses decreased $20 million primarily due to the following:
  - A $16 million decrease in depreciation expense due to the retirement of the Oklaunion Power Station in September 2020.This decrease was partially offset above in Margins from Off-system Sales and Other Operation and Maintenance expenses.
  - A $9 million decrease in securitization amortizations primarily related to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Other Revenues above.

  These decreases were partially offset by:
  - A $7 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- **Allowance for Equity Funds Used During Construction** increased $5 million due to a current year adjustment to rates.
- **Income Tax Expense** increased $14 million primarily due to an increase in pretax book income, a decrease in amortization of Excess ADIT and the recognition of a favorable discrete adjustment in the prior year. The decrease in amortization of Excess ADIT was partially offset above in Gross Margin.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

AEP Texas Inc. and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Net Income
(in millions)

Nine Months Ended September 30, 2020	$	197.1
Changes in Gross Margin:		
Retail Margins		54.2
Margins from Off-system Sales		(73.2)
Transmission Revenues		74.5
Other Revenues		(103.7)
Total Change in Gross Margin		(48.2)
Changes in Expenses and Other:		
Other Operation and Maintenance		(18.1)
Depreciation and Amortization		148.7
Taxes Other Than Income Taxes		(10.7)
Interest Income		(0.6)
Allowance for Equity Funds Used During Construction		2.3
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		(3.3)
Total Change in Expenses and Other		118.2
Income Tax Expense		(41.7)
Nine Months Ended September 30, 2021	$	225.4

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

- **Retail Margins** increased $54 million primarily due to the following:
  - A $34 million increase from interim rate increases driven by increased distribution investment.
  - An $18 million increase from interim rate increases driven by increased transmission investment.
  - A $10 million increase in weather-related usage primarily due to a 226% increase in heating degree days partially offset by a 10% decrease in cooling degree days.

  These increases were partially offset by:
  - An $8 million decrease in weather-normalized margins primarily in the industrial class.
- **Margins from Off-system Sales** decreased $73 million primarily due to the retirement of the Oklaunion Power Station in September 2020.This decrease was partially offset in Depreciation and Amortization expenses below.
- **Transmission Revenues** increased $75 million primarily due to the following:
  - A $59 million increase from interim rate increases driven by increased transmission investment.
  - A $14 million increase due to a prior year one-time credit to transmission customers as a result of Tax Reform and the most recent base rate case. This increase was offset in Income Tax Expense below.
- **Other Revenues** decreased $104 million primarily due to securitization revenues driven by the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset below in Depreciation and Amortization expenses and in Interest Expense.

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

- **Other Operation and Maintenance** expenses increased $18 million primarily due to the following:
  - A $17 million increase due to the prior year revision of the Oklaunion Power Station ARO.This increase was offset in Margins from Off-System Sales above.
  - An $8 million increase in transmission expenses. This increase was partially offset in Gross Margin above.

  These increases were partially offset by:
  - A $5 million decrease due to the prior year write-off of land associated with the Oklaunion Power Station.
- **Depreciation and Amortization** expenses decreased $149 million primarily due to the following:
  - A $102 million decrease in securitization amortizations primarily related to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Other Revenues above.
  - A $48 million decrease in depreciation expense due to the retirement of the Oklaunion Power Station in September 2020.This decrease was partially offset above in Margins from Off-system Sales and Other Operation and Maintenance expenses.
- **Taxes Other Than Income Taxes** increased $11 million primarily due to property taxes as a result of increased distribution and transmission investment.
- **Interest Expense** increased $3 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $42 million primarily due to a decrease in amortization of Excess ADIT and an increase in pretax book income. The decrease in amortization of Excess ADIT was partially offset above in Gross Margin.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
REVENUES				
Electric Transmission and Distribution	$ 430.8	$ 390.1	$ 1,189.1	$ 1,165.2
Sales to AEP Affiliates	0.9	41.4	2.9	89.4
Other Revenues	0.9	0.5	3.3	2.5
TOTAL REVENUES	432.6	432.0	1,195.3	1,257.1
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	—	10.4	—	13.6
Other Operation	135.3	134.3	367.1	344.7
Maintenance	22.0	20.4	59.8	64.1
Depreciation and Amortization	87.6	107.7	287.1	435.8
Taxes Other Than Income Taxes	41.6	38.7	117.4	106.7
TOTAL EXPENSES	286.5	311.5	831.4	964.9
OPERATING INCOME	146.1	120.5	363.9	292.2
Other Income (Expense):				
Interest Income	0.2	0.5	0.6	1.2
Allowance for Equity Funds Used During Construction	9.2	4.4	16.7	14.4
Non-Service Cost Components of Net Periodic Benefit Cost	2.8	2.8	8.3	8.4
Interest Expense	(44.2)	(44.5)	(132.5)	(129.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	114.1	83.7	257.0	187.0
Income Tax Expense (Benefit)	14.6	1.1	31.6	(10.1)
NET INCOME	$ 99.5	$ 82.6	$ 225.4	$ 197.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net Income	$ 99.5	$ 82.6	$ 225.4	$ 197.1
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $0.2 and $0.2 for the Nine Months Ended September 30, 2021 and 2020, Respectively	0.3	0.3	0.8	0.8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2021 and 2020, Respectively	—	—	0.1	0.1
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3	0.9	0.9
TOTAL COMPREHENSIVE INCOME	$ 99.8	$ 82.9	$ 226.3	$ 198.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 1,457.9	$ 1,516.0	$ (12.8)	$ 2,961.1
Net Income		47.6		47.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	1,457.9	1,563.6	(12.5)	3,009.0
Net Income		66.9		66.9
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2020	1,457.9	1,630.5	(12.2)	3,076.2
Net Income		82.6		82.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2020	$ 1,457.9	$ 1,713.1	$ (11.9)	$ 3,159.1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 1,457.9	$ 1,757.0	$ (8.9)	$ 3,206.0
Net Income		46.1		46.1
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	1,457.9	1,803.1	(8.6)	3,252.4
Net Income		79.8		79.8
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2021	1,457.9	1,882.9	(8.3)	3,332.5
Net Income		99.5		99.5
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2021	$ 1,457.9	$ 1,982.4	$ (8.0)	$ 3,432.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (September 30, 2021 and December 31, 2020 Amounts Include $43.9 and $28.7, Respectively, Related to Transition Funding and Restoration Funding)	43.9	28.7
Advances to Affiliates	54.6	7.1
Accounts Receivable:		
Customers	142.1	112.8
Affiliated Companies	4.8	5.1
Accrued Unbilled Revenues	81.0	65.8
Allowance for Uncollectible Accounts	(4.1)	(0.1)
Total Accounts Receivable	223.8	183.6
Materials and Supplies	72.5	70.0
Accrued Tax Benefits	23.7	16.8
Prepayments and Other Current Assets	6.9	4.6
TOTAL CURRENT ASSETS	425.5	310.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	5,627.1	5,279.6
Distribution	4,823.7	4,580.8
Other Property, Plant and Equipment	944.3	868.4
Construction Work in Progress	539.4	614.1
Total Property, Plant and Equipment	11,934.5	11,342.9
Accumulated Depreciation and Amortization	1,621.1	1,529.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,313.4	9,813.6
OTHER NONCURRENT ASSETS		
Regulatory Assets	290.4	266.8
Securitized Assets (September 30, 2021 and December 31, 2020 Amounts Include $389.1 and $446.8, Respectively, Related to Transition Funding and Restoration Funding)	389.1	446.8
Deferred Charges and Other Noncurrent Assets	213.1	192.1
TOTAL OTHER NONCURRENT ASSETS	892.6	905.7
TOTAL ASSETS	$ 11,631.5	$ 11,030.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

		September 30, 2021	December 31, 2020
CURRENT LIABILITIES			
Advances from Affiliates	$	— $	67.1
Accounts Payable:			
General		194.3	231.7
Affiliated Companies		29.4	44.0
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2021 and December 31, 2020 Amounts Include $90.1 and $88.7, Respectively, Related to Transition Funding and Restoration Funding)		315.1	88.7
Accrued Taxes		114.7	78.3
Accrued Interest (September 30, 2021 and December 31, 2020 Amounts Include $3 and $2.5, Respectively, Related to Transition Funding and Restoration Funding)		60.7	43.9
Obligations Under Operating Leases		14.1	14.5
Other Current Liabilities		98.4	108.6
TOTAL CURRENT LIABILITIES		826.7	676.8
NONCURRENT LIABILITIES			
Long-term Debt – Nonaffiliated (September 30, 2021 and December 31, 2020 Amounts Include $350.9 and $403.9, Respectively, Related to Transition Funding and Restoration Funding)		4,901.0	4,731.7
Deferred Income Taxes		1,087.1	1,016.7
Regulatory Liabilities and Deferred Investment Tax Credits		1,256.8	1,270.8
Obligations Under Operating Leases		64.5	71.0
Deferred Credits and Other Noncurrent Liabilities		63.1	57.2
TOTAL NONCURRENT LIABILITIES		7,372.5	7,147.4
TOTAL LIABILITIES		8,199.2	7,824.2
Rate Matters (Note 4)			
Commitments and Contingencies (Note 5)			
COMMON SHAREHOLDER'S EQUITY			
Paid-in Capital		1,457.9	1,457.9
Retained Earnings		1,982.4	1,757.0
Accumulated Other Comprehensive Income (Loss)		(8.0)	(8.9)
TOTAL COMMON SHAREHOLDER'S EQUITY		3,432.3	3,206.0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$	11,631.5 $	11,030.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
OPERATING ACTIVITIES		
Net Income	$ 225.4	$ 197.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	287.1	435.8
Deferred Income Taxes	45.8	(11.5)
Allowance for Equity Funds Used During Construction	(16.7)	(14.4)
Mark-to-Market of Risk Management Contracts	—	0.1
Pension Contributions to Qualified Plan Trust	—	(11.3)
Change in Other Noncurrent Assets	(73.4)	(77.3)
Change in Other Noncurrent Liabilities	17.5	(30.0)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(40.2)	(40.2)
Fuel, Materials and Supplies	(2.5)	(9.4)
Accounts Payable	(10.9)	24.2
Accrued Taxes, Net	29.5	73.4
Other Current Assets	(2.0)	(0.8)
Other Current Liabilities	(5.0)	(49.8)
Net Cash Flows from Operating Activities	454.6	485.9
INVESTING ACTIVITIES		
Construction Expenditures	(742.4)	(976.1)
Change in Advances to Affiliates, Net	(47.5)	58.8
Other Investing Activities	29.6	24.1
Net Cash Flows Used for Investing Activities	(760.3)	(893.2)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	444.2	652.8
Change in Short-term Debt, Net – Nonaffiliated	—	2.0
Change in Advances from Affiliates, Net	(67.1)	—
Retirement of Long-term Debt – Nonaffiliated	(52.2)	(356.5)
Principal Payments for Finance Lease Obligations	(5.0)	(4.7)
Other Financing Activities	1.0	0.8
Net Cash Flows from Financing Activities	320.9	294.4
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	15.2	(112.9)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	28.8	157.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 44.0	$ 44.9
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 110.0	$ 102.0
Net Cash Paid (Received) for Income Taxes	(8.4)	(55.6)
Noncash Acquisitions Under Finance Leases	3.3	5.1
Construction Expenditures Included in Current Liabilities as of September 30,	134.9	167.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30,	
	2021	2020
	(in millions)	
Plant In Service	$ 10,851.9	$ 9,240.4
Construction Work in Progress	1,507.4	1,680.9
Accumulated Depreciation and Amortization	730.4	531.8
Total Transmission Property, Net	$ 11,628.9	$ 10,389.5

Third Quarter of 2021 Compared to Third Quarter of 2020

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Net Income
(in millions)

Third Quarter of 2020	$ 117.6
Changes in Transmission Revenues:	
Transmission Revenues	72.9
Total Change in Transmission Revenues	72.9
Changes in Expenses and Other:	
Other Operation and Maintenance	(9.2)
Depreciation and Amortization	(14.5)
Taxes Other Than Income Taxes	(8.8)
Allowance for Equity Funds Used During Construction	(4.2)
Interest Expense	(3.4)
Total Change in Expenses and Other	(40.1)
Income Tax Expense	(5.0)
Third Quarter of 2021	$ 145.4

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

- **Transmission Revenues** increased $73 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $9 million primarily due to the following:
  - A $2 million increase in vegetation management expenses.
  - A $2 million increase in an accrual for NERC compliance costs.
  - A $2 million increase in employee-related expenses.
  - A $1 million increase in rent expense.
- **Depreciation and Amortization** expenses increased $15 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** decreased $4 million primarily due to lower CWIP.
- **Interest Expense** increased $3 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $5 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Net Income
(in millions)

Nine Months Ended September 30, 2020	$	309.1
Changes in Transmission Revenues:		
Transmission Revenues		266.4
Total Change in Transmission Revenues		266.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(11.6)
Depreciation and Amortization		(42.6)
Taxes Other Than Income Taxes		(26.1)
Interest Income		(1.9)
Allowance for Equity Funds Used During Construction		(5.6)
Interest Expense		(9.4)
Total Change in Expenses and Other		(97.2)
Income Tax Expense		(32.6)
Nine Months Ended September 30, 2021	$	445.7

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

- **Transmission Revenues** increased $266 million primarily due to the following:
  - A $204 million increase due to continued investment in transmission assets.
  - A $45 million increase as a result of the affiliated annual transmission formula rate true-up which is offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $14 million increase as a result of the non-affiliated annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
  - A $4 million increase in vegetation management expenses.
  - A $2 million increase in an accrual for NERC compliance costs.
  - A $2 million increase in rent expense.
  - A $1 million increase in property insurance premiums.
- **Depreciation and Amortization** expenses increased $43 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $26 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $6 million primarily due to lower CWIP.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $33 million primarily due to an increase in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
REVENUES				
Transmission Revenues	$ 79.2	$ 62.9	$ 239.3	$ 184.6
Sales to AEP Affiliates	297.6	241.2	864.6	652.6
Other Revenues	0.2	—	0.3	0.6
TOTAL REVENUES	377.0	304.1	1,104.2	837.8
EXPENSES				
Other Operation	32.6	25.3	78.1	72.0
Maintenance	5.4	3.5	12.3	6.8
Depreciation and Amortization	76.0	61.5	219.0	176.4
Taxes Other Than Income Taxes	61.0	52.2	178.9	152.8
TOTAL EXPENSES	175.0	142.5	488.3	408.0
OPERATING INCOME	202.0	161.6	615.9	429.8
Other Income (Expense):				
Interest Income - Affiliated	0.2	0.2	0.4	2.3
Allowance for Equity Funds Used During Construction	16.0	20.2	49.3	54.9
Interest Expense	(36.1)	(32.7)	(104.5)	(95.1)
INCOME BEFORE INCOME TAX EXPENSE	182.1	149.3	561.1	391.9
Income Tax Expense	36.7	31.7	115.4	82.8
NET INCOME	$ 145.4	$ 117.6	$ 445.7	$ 309.1

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2019	$ 2,480.6	$ 1,528.9	$ 4,009.5
Capital Contribution from Member	185.0		185.0
Net Income		117.8	117.8
TOTAL MEMBER'S EQUITY – MARCH 31, 2020	2,665.6	1,646.7	4,312.3
Dividends Paid to Member		(5.0)	(5.0)
Net Income		73.7	73.7
TOTAL MEMBER'S EQUITY – JUNE 30, 2020	2,665.6	1,715.4	4,381.0
Net Income		117.6	117.6
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2020	$ 2,665.6	$ 1,833.0	$ 4,498.6
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2020	$ 2,765.6	$ 1,947.3	$ 4,712.9
Capital Contribution from Member	124.0		124.0
Net Income		151.7	151.7
TOTAL MEMBER'S EQUITY – MARCH 31, 2021	2,889.6	2,099.0	4,988.6
Capital Contribution from Member	60.0		60.0
Net Income		148.6	148.6
TOTAL MEMBER'S EQUITY – JUNE 30, 2021	2,949.6	2,247.6	5,197.2
Dividends Paid to Member		(112.5)	(112.5)
Net Income		145.4	145.4
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2021	$ 2,949.6	$ 2,280.5	$ 5,230.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Advances to Affiliates	$ 79.2	$ 109.1
Accounts Receivable:		
Customers	31.0	22.9
Affiliated Companies	96.7	81.2
Total Accounts Receivable	127.7	104.1
Materials and Supplies	9.0	8.5
Prepayments and Other Current Assets	3.5	14.1
TOTAL CURRENT ASSETS	219.4	235.8
TRANSMISSION PROPERTY		
Transmission Property	10,458.4	9,593.5
Other Property, Plant and Equipment	393.5	329.5
Construction Work in Progress	1,507.4	1,422.6
Total Transmission Property	12,359.3	11,345.6
Accumulated Depreciation and Amortization	730.4	572.8
TOTAL TRANSMISSION PROPERTY – NET	11,628.9	10,772.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	10.1	15.1
Deferred Property Taxes	66.1	220.1
Deferred Charges and Other Noncurrent Assets	6.6	2.2
TOTAL OTHER NONCURRENT ASSETS	82.8	237.4
TOTAL ASSETS	$ 11,931.1	$ 11,246.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT LIABILITIES		
Advances from Affiliates	$ 13.9	$ 156.7
Accounts Payable:		
General	298.8	380.4
Affiliated Companies	67.6	97.3
Long-term Debt Due Within One Year – Nonaffiliated	50.0	50.0
Accrued Taxes	269.5	418.1
Accrued Interest	50.2	23.9
Obligations Under Operating Leases	0.9	1.2
Other Current Liabilities	8.1	9.9
TOTAL CURRENT LIABILITIES	759.0	1,137.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,343.4	3,898.5
Deferred Income Taxes	955.2	906.9
Regulatory Liabilities	633.9	581.8
Obligations Under Operating Leases	1.0	0.4
Deferred Credits and Other Noncurrent Liabilities	8.5	8.0
TOTAL NONCURRENT LIABILITIES	5,942.0	5,395.6
TOTAL LIABILITIES	6,701.0	6,533.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	2,949.6	2,765.6
Retained Earnings	2,280.5	1,947.3
TOTAL MEMBER'S EQUITY	5,230.1	4,712.9
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,931.1	$ 11,246.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
OPERATING ACTIVITIES		
Net Income	$ 445.7	$ 309.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	219.0	176.4
Deferred Income Taxes	46.8	65.4
Allowance for Equity Funds Used During Construction	(49.3)	(54.9)
Property Taxes	154.0	136.3
Change in Other Noncurrent Assets	2.3	(1.5)
Change in Other Noncurrent Liabilities	8.3	19.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(23.6)	(30.1)
Materials and Supplies	(0.5)	0.2
Accounts Payable	(10.7)	26.0
Accrued Taxes, Net	(138.8)	(139.0)
Accrued Interest	26.3	29.0
Other Current Assets	0.5	9.1
Other Current Liabilities	(3.6)	(10.7)
Net Cash Flows from Operating Activities	676.4	534.8
INVESTING ACTIVITIES		
Construction Expenditures	(1,070.8)	(1,163.8)
Change in Advances to Affiliates, Net	29.9	(21.3)
Other Investing Activities	(7.9)	1.1
Net Cash Flows Used for Investing Activities	(1,048.8)	(1,184.0)
FINANCING ACTIVITIES		
Capital Contributions from Member	184.0	185.0
Issuance of Long-term Debt – Nonaffiliated	443.7	519.4
Change in Advances from Affiliates, Net	(142.8)	(50.2)
Dividends Paid to Member	(112.5)	(5.0)
Net Cash Flows from Financing Activities	372.4	649.2
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 75.8	$ 63.3
Net Cash Paid for Income Taxes	37.6	1.9
Construction Expenditures Included in Current Liabilities as of September 30,	206.8	283.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions of KWhs)			
Retail:				
Residential	2,657	2,772	8,524	8,229
Commercial	1,596	1,612	4,483	4,410
Industrial	2,223	2,193	6,590	6,507
Miscellaneous	206	203	602	585
Total Retail	6,682	6,780	20,199	19,731
Wholesale	1,414	1,187	3,636	2,894
Total KWhs	8,096	7,967	23,835	22,625

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in degree days)			
Actual – Heating (a)	—	1	1,397	1,098
Normal – Heating (b)	2	2	1,404	1,413
Actual – Cooling (c)	945	988	1,330	1,354
Normal – Cooling (b)	831	825	1,214	1,208

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Appalachian Power Company and Subsidiaries
Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Net Income
(in millions)

Third Quarter of 2020	$	116.6
Changes in Gross Margin:		
Retail Margins		40.7
Margins from Off-system Sales		0.5
Transmission Revenues		7.7
Other Revenues		(0.3)
Total Change in Gross Margin		48.6
Changes in Expenses and Other:		
Other Operation and Maintenance		(53.8)
Depreciation and Amortization		(12.2)
Taxes Other Than Income Taxes		(1.0)
Interest Income		(0.4)
Allowance for Equity Funds Used During Construction		(2.4)
Interest Expense		2.2
Total Change in Expenses and Other		(67.6)
Income Tax Expense		(11.3)
Third Quarter of 2021	$	86.3

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 $41 million primarily due to the following:
  - A $40 million increase due to rider revenues primarily in Virginia. This increase was partially offset in other expense items below.
  - A $10 million increase due to lower customer refunds related to Tax Reform. This increase was partially offset in Income Tax Expense below.
  - A $6 million increase in weather-normalized margins driven by an increase in the industrial class, partially offset by a decrease in the residential class.

  These increases were partially offset by:
  - An $11 million decrease in deferred fuel primarily due to the timing of expenses recovered through the Expanded Net Energy Cost (ENEC). This decrease was offset in expense items below.
  - A $4 million decrease in weather-related usage primarily driven by a 4% decrease in cooling degree days.
- **Transmission Revenues** increased $8 million primarily due to an increase in transmission investment. This increase was partially offset in Depreciation and Amortization expenses below.

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

- **Other Operation and Maintenance** expenses increased $54 million primarily due to the following:
  - A $33 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $13 million increase in vegetation management expenses. This increase was partially offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $12 million primarily due to an increase in depreciation rates in Virginia and a higher depreciable base. This increase was partially offset in Retail Margins and Transmission Revenues above.

- **Income Tax Expense** increased $11 million primarily due to a decrease in amortization of Excess ADIT. This increase was partially offset in Retail Margins above.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Appalachian Power Company and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Net Income
(in millions)

Nine Months Ended September 30, 2020	$	313.2
Changes in Gross Margin:		
Retail Margins		103.0
Margins from Off-system Sales		2.8
Transmission Revenues		21.9
Other Revenues		(1.2)
Total Change in Gross Margin		126.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(98.7)
Depreciation and Amortization		(40.6)
Taxes Other Than Income Taxes		(2.5)
Interest Income		(0.6)
Allowance for Equity Funds Used During Construction		0.6
Non-Service Cost Components of Net Periodic Benefit Cost		0.1
Interest Expense		1.6
Total Change in Expenses and Other		(140.1)
Income Tax Expense		(24.5)
Nine Months Ended September 30, 2021	$	275.1

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 $103 million primarily due to the following:
  - A $63 million increase due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - A $30 million increase in weather-related usage primarily driven by a 27% increase in heating degree days.
  - A $10 million increase in weather-normalized margins primarily driven by increases in the commercial and industrial classes, partially offset by a decrease in the residential class.
  - A $9 million increase due to lower customer refunds related to Tax Reform. This increase was partially offset in Income Tax Expense below.

  These increases were partially offset by:
  - A $7 million decrease in deferred fuel primarily due to the timing of expenses recovered through the ENEC.This decrease was offset in expense items below.
- **Transmission Revenues** increased $22 million primarily due to an increase in transmission investment. This increase was partially offset in Depreciation and Amortization expenses below.

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

- **Other Operation and Maintenance** expenses increased $99 million primarily due to the following:
  - A $44 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $40 million increase in vegetation management expenses. This increase was partially offset in Retail Margins above.

- A $13 million increase in PJM transmission expenses as a result of the annual transmission formula rate true-up. This increase was partially offset in Retail Margins above.
- A $7 million increase due to the current year amortization of regulatory assets related to the 2017-2019 Virginia triennial review which authorized regulatory recovery of previously retired coal-fired generation assets.

These increases were partially offset by:

- A $6 million decrease in distribution expenses related to storm restoration costs.

- **Depreciation and Amortization** expenses increased $41 million primarily due to an increase in depreciation rates in Virginia and a higher depreciable base. This increase was partially offset in Retail Margins and Transmission Revenues above.
- **Income Tax Expense** increased $25 million primarily due to a decrease in amortization of Excess ADIT. This increase was partially offset in Retail Margins above.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
REVENUES				
Electric Generation, Transmission and Distribution	$ 748.5	$ 688.9	$ 2,149.2	$ 1,989.9
Sales to AEP Affiliates	52.4	44.4	140.6	124.9
Other Revenues	3.1	2.4	8.2	7.8
TOTAL REVENUES	804.0	735.7	2,298.0	2,122.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	170.8	166.0	471.9	430.9
Purchased Electricity for Resale	82.4	67.5	248.4	240.5
Other Operation	173.0	136.3	442.1	379.1
Maintenance	69.1	52.0	184.4	148.7
Depreciation and Amortization	135.4	123.2	406.6	366.0
Taxes Other Than Income Taxes	39.8	38.8	116.7	114.2
TOTAL EXPENSES	670.5	583.8	1,870.1	1,679.4
OPERATING INCOME	133.5	151.9	427.9	443.2
Other Income (Expense):				
Interest Income	0.2	0.6	0.8	1.4
Allowance for Equity Funds Used During Construction	4.3	6.7	12.1	11.5
Non-Service Cost Components of Net Periodic Benefit Cost	4.7	4.7	14.2	14.1
Interest Expense	(52.8)	(55.0)	(160.6)	(162.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	89.9	108.9	294.4	308.0
Income Tax Expense (Benefit)	3.6	(7.7)	19.3	(5.2)
NET INCOME	$ 86.3	$ 116.6	$ 275.1	$ 313.2

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net Income	$ 86.3	$ 116.6	$ 275.1	$ 313.2
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0.1 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $2.3 and $(1.2) for Nine Months Ended September 30, 2021 and 2020, Respectively	(0.3)	0.6	8.5	(4.4)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.3) for the Three Months Ended September 30, 2021 and 2020, Respectively, and $(0.8) and $(0.8) for the Nine Months Ended September 30, 2021 and 2020, Respectively	(1.0)	(0.9)	(3.1)	(2.8)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(1.3)	(0.3)	5.4	(7.2)
TOTAL COMPREHENSIVE INCOME	$ 85.0	$ 116.3	$ 280.5	$ 306.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2019	$ 260.4	$ 1,828.7	$ 2,078.3	$ 5.0	$ 4,172.4
Common Stock Dividends			(50.0)		(50.0)
Net Income			115.3		115.3
Other Comprehensive Loss				(5.1)	(5.1)
TOTAL COMMON SHAREHOLDER'S EQUITY -MARCH 31, 2020	260.4	1,828.7	2,143.6	(0.1)	4,232.6
Common Stock Dividends			(50.0)		(50.0)
Net Income			81.3		81.3
Other Comprehensive Loss				(1.8)	(1.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2020	$ 260.4	$ 1,828.7	$ 2,174.9	$ (1.9)	$ 4,262.1
Common Stock Dividends			(50.0)		(50.0)
Net Income			116.6		116.6
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2020	$ 260.4	$ 1,828.7	$ 2,241.5	$ (2.2)	$ 4,328.4
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2020	$ 260.4	$ 1,828.7	$ 2,248.0	$ 7.2	$ 4,344.3
Common Stock Dividends			(12.5)		(12.5)
Net Income			122.5		122.5
Other Comprehensive Income				7.9	7.9
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2021	260.4	1,828.7	2,358.0	15.1	4,462.2
Common Stock Dividends			(12.5)		(12.5)
Net Income			66.3		66.3
Other Comprehensive Loss				(1.2)	(1.2)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2021	$ 260.4	$ 1,828.7	$ 2,411.8	$ 13.9	$ 4,514.8
Common Stock Dividends			(12.5)		(12.5)
Net Income			86.3		86.3
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2021	$ 260.4	$ 1,828.7	$ 2,485.6	$ 12.6	$ 4,587.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5.0	$ 5.8
Restricted Cash for Securitized Funding	10.1	16.9
Advances to Affiliates	185.2	21.4
Accounts Receivable:		
Customers	119.3	142.8
Affiliated Companies	77.4	64.3
Accrued Unbilled Revenues	53.6	80.1
Miscellaneous	0.2	0.3
Allowance for Uncollectible Accounts	(1.6)	(3.1)
Total Accounts Receivable	248.9	284.4
Fuel	66.6	193.6
Materials and Supplies	100.3	99.6
Risk Management Assets	47.0	22.4
Regulatory Asset for Under-Recovered Fuel Costs	49.2	5.3
Prepayments and Other Current Assets	72.1	24.7
TOTAL CURRENT ASSETS	784.4	674.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,670.8	6,633.7
Transmission	4,052.9	3,900.5
Distribution	4,621.1	4,464.3
Other Property, Plant and Equipment	682.4	627.2
Construction Work in Progress	567.7	484.6
Total Property, Plant and Equipment	16,594.9	16,110.3
Accumulated Depreciation and Amortization	4,973.1	4,716.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,621.8	11,394.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	818.6	686.3
Securitized Assets	191.3	210.1
Employee Benefits and Pension Assets	156.8	150.1
Operating Lease Assets	70.4	78.8
Deferred Charges and Other Noncurrent Assets	93.5	121.7
TOTAL OTHER NONCURRENT ASSETS	1,330.6	1,247.0
TOTAL ASSETS	$ 13,736.8	$ 13,315.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2021 and December 31, 2020
(Unaudited)

	September 30, 2021	December 31, 2020
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 18.6
Accounts Payable:		
General	224.7	212.0
Affiliated Companies	97.2	97.1
Long-term Debt Due Within One Year – Nonaffiliated	380.6	518.3
Customer Deposits	72.9	77.8
Accrued Taxes	88.5	109.9
Accrued Interest	80.0	49.9
Obligations Under Operating Leases	15.1	14.9
Other Current Liabilities	107.6	119.2
TOTAL CURRENT LIABILITIES	1,066.6	1,217.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,557.2	4,315.8
Deferred Income Taxes	1,739.3	1,749.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,250.9	1,224.7
Asset Retirement Obligations	393.6	304.8
Employee Benefits and Pension Obligations	42.9	44.0
Obligations Under Operating Leases	55.9	64.4
Deferred Credits and Other Noncurrent Liabilities	43.1	49.6
TOTAL NONCURRENT LIABILITIES	8,082.9	7,753.2
TOTAL LIABILITIES	9,149.5	8,970.9
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	2,485.6	2,248.0
Accumulated Other Comprehensive Income (Loss)	12.6	7.2
TOTAL COMMON SHAREHOLDER'S EQUITY	4,587.3	4,344.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 13,736.8	$ 13,315.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
OPERATING ACTIVITIES		
Net Income	$ 275.1	$ 313.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	406.6	366.0
Deferred Income Taxes	(12.0)	(28.2)
Allowance for Equity Funds Used During Construction	(12.1)	(11.5)
Mark-to-Market of Risk Management Contracts	(26.8)	8.0
Pension Contributions to Qualified Plan Trust	—	(7.0)
Deferred Fuel Over/Under-Recovery, Net	(43.9)	38.8
Change in Other Noncurrent Assets	(39.2)	5.4
Change in Other Noncurrent Liabilities	20.2	(26.0)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	38.1	7.2
Fuel, Materials and Supplies	126.3	12.4
Accounts Payable	26.5	(74.0)
Accrued Taxes, Net	(48.0)	1.9
Other Current Assets	(20.7)	10.1
Other Current Liabilities	0.5	(9.7)
Net Cash Flows from Operating Activities	690.6	606.6
INVESTING ACTIVITIES		
Construction Expenditures	(586.4)	(566.6)
Change in Advances to Affiliates, Net	(163.8)	(137.4)
Other Investing Activities	12.4	4.6
Net Cash Flows Used for Investing Activities	(737.8)	(699.4)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	494.0	557.2
Change in Advances from Affiliates, Net	(18.6)	(232.4)
Retirement of Long-term Debt – Nonaffiliated	(393.0)	(90.3)
Principal Payments for Finance Lease Obligations	(5.8)	(5.6)
Dividends Paid on Common Stock	(37.5)	(150.0)
Other Financing Activities	0.5	0.3
Net Cash Flows from Financing Activities	39.6	79.2
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(7.6)	(13.6)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	22.7	26.8
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 15.1	$ 13.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 124.2	$ 130.0
Net Cash Paid (Received) for Income Taxes	52.6	(10.7)
Noncash Acquisitions Under Finance Leases	1.3	3.0
Construction Expenditures Included in Current Liabilities as of September 30,	92.3	90.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions of KWhs)			
Retail:				
Residential	1,531	1,531	4,244	4,230
Commercial	1,267	1,219	3,481	3,362
Industrial	1,853	1,849	5,542	5,324
Miscellaneous	13	14	42	47
Total Retail	4,664	4,613	13,309	12,963
Wholesale	1,610	1,536	5,055	5,552
Total KWhs	6,274	6,149	18,364	18,515

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in degree days)			
Actual – Heating (a)	2	7	2,343	2,186
Normal – Heating (b)	9	10	2,417	2,429
Actual – Cooling (c)	679	637	1,004	923
Normal – Cooling (b)	581	576	848	841

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Indiana Michigan Power Company and Subsidiaries
Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Net Income
(in millions)

Third Quarter of 2020	$	76.7
Changes in Gross Margin:		
Retail Margins		30.9
Margins from Off-system Sales		0.2
Transmission Revenues		(0.2)
Other Revenues		4.0
Total Change in Gross Margin		34.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(3.0)
Depreciation and Amortization		(6.1)
Taxes Other Than Income Taxes		(0.4)
Other Income		0.3
Interest Expense		(3.3)
Total Change in Expenses and Other		(12.5)
Income Tax Expense		5.0
Third Quarter of 2021	$	104.1

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 $31 million primarily due to the following:
  - A $40 million increase primarily due to an increase in rider revenues and the reversal of a provision for refund. This increase was partially offset in other expense items below.
  - A $4 million increase in weather-related usage primarily due to a 7 % increase in cooling degree days.
  - A $2 million decrease in fuel related expenses due to timing of recovery related to wholesale contracts.

  These increases were partially offset by:
  - A $19 million decrease in weather-normalized retail margins primarily in the residential class.
- **Other Revenues** increased $4 million primarily due to increases in barging revenues by River Transportation Division (RTD), reconnection fees and joint license agreements. The increase in RTD barging revenues are partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $3 million primarily due to the following:
  - A $10 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $5 million increase in distribution expenses primarily due to an increase in vegetation management expenses.
  - A $2 million increase in nonutility operation expenses primarily due to an increase in RTD expenses. This increase was partially offset in Other Revenues above.

  These increases were partially offset by:
  - A $9 million decrease in employee-related expenses.
  - A $7 million decrease in Indiana jurisdictional Demand Side Management expenses. This decrease was offset in Retail Margins above.

- **Depreciation and Amortization** expenses increased $6 million primarily due to a higher depreciable base. This increase was partially offset in Retail Margins above.
- **Income Tax Expense** decreased $5 million primarily due to an increase in amortization of Excess ADIT and flow through tax benefits and an unfavorable discrete tax adjustment recorded in 2020 that did not recur in 2021, partially offset by an increase to pretax book income. The increase in amortization of Excess ADIT is partially offset above in Retail Margins.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Indiana Michigan Power Company and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Net Income
(in millions)

Nine Months Ended September 30, 2020	$	232.8
Changes in Gross Margin:		
Retail Margins		57.0
Transmission Revenues		(5.2)
Other Revenues		4.0
Total Change in Gross Margin		55.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(43.7)
Depreciation and Amortization		(25.1)
Taxes Other Than Income Taxes		(4.3)
Other Income		1.1
Non-Service Cost Components of Net Periodic Benefit Cost		(0.2)
Interest Expense		(0.9)
Total Change in Expenses and Other		(73.1)
Income Tax Expense		16.6
Nine Months Ended September 30, 2021	$	232.1

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 $57 million primarily due to the following:
  - An $88 million increase due to the annual wholesale formula rate true-up, an increase in Indiana and Michigan base rate revenues and an increase in rider revenues. This increase was partially offset in other expense items below.
  - A $14 million increase in weather-related usage primarily due to a 7% increase in heating degree days and a 9% increase in cooling degree days.
  - A $5 million decrease in fuel related expenses due to timing of recovery related to wholesale contracts.

  These increases were partially offset by:
  - A $36 million decrease in weather-normalized retail margins primarily in the residential class.
  - A $24 million decrease in weather-normalized wholesale margins, including the loss of a significant wholesale contract.
- **Transmission Revenues** decreased $5 million primarily due to the annual transmission formula rate true-up.
- **Other Revenues** increased $4 million primarily due to an increase in reconnection fees and joint license agreements.

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

- **Other Operation and Maintenance** expenses increased $44 million primarily due to the following:
  - A $27 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $17 million increase in transmission expenses primarily due to an $8 million increase in vegetation management expenses and a $6 million increase as a result of the annual transmission formula rate true-up.

- An $8 million increase in distribution expenses primarily due to an increase in vegetation management expenses.
- A $4 million increase due to a decreased Nuclear Electric Insurance Limited distribution in 2021.

These increases were partially offset by:

- A $17 million decrease in Indiana jurisdictional Demand Side Management expenses. This decrease was offset in Retail Margins above.
- A $4 million decrease in nuclear expenses primarily due to a $9 million decrease in Cook Plant refueling outage expenses partially offset by a $5 million increase in various maintenance activities.

- **Depreciation and Amortization** expenses increased $25 million primarily due to a higher depreciable base and an increase in depreciation rates. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $4 million primarily due to property taxes driven by an increase in utility plant and higher tax rates.
- **Income Tax Expense** decreased $17 million primarily due to an increase in flow through tax benefits, a decrease in state income tax expense and a decrease in pretax book income.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
REVENUES				
Electric Generation, Transmission and Distribution	$ 618.2	$ 570.1	$ 1,735.1	$ 1,648.4
Sales to AEP Affiliates	1.1	1.3	2.6	9.1
Other Revenues – Affiliated	14.7	14.1	41.2	42.4
Other Revenues – Nonaffiliated	1.7	1.2	5.1	3.7
TOTAL REVENUES	635.7	586.7	1,784.0	1,703.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	43.7	44.4	129.9	146.0
Purchased Electricity for Resale	44.9	37.5	131.9	128.1
Purchased Electricity from AEP Affiliates	63.3	55.9	172.7	135.8
Other Operation	167.5	165.5	482.4	459.7
Maintenance	52.0	51.0	165.4	144.4
Depreciation and Amortization	110.6	104.5	328.7	303.6
Taxes Other Than Income Taxes	27.8	27.4	83.8	79.5
TOTAL EXPENSES	509.8	486.2	1,494.8	1,397.1
OPERATING INCOME	125.9	100.5	289.2	306.5
Other Income (Expense):				
Other Income	2.5	2.2	8.9	7.8
Non-Service Cost Components of Net Periodic Benefit Cost	4.1	4.1	12.3	12.5
Interest Expense	(30.2)	(26.9)	(86.6)	(85.7)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	102.3	79.9	223.8	241.1
Income Tax Expense (Benefit)	(1.8)	3.2	(8.3)	8.3
NET INCOME	$ 104.1	$ 76.7	$ 232.1	$ 232.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
Net Income	$ 104.1	$ 76.7	$ 232.1	$ 232.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $0.3 and $0.3 for the Nine Months Ended September 30, 2021 and 2020, Respectively	0.4	0.4	1.3	1.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2021 and 2020, Respectively	—	(0.1)	(0.1)	(0.1)
TOTAL OTHER COMPREHENSIVE INCOME	0.4	0.3	1.2	1.1
TOTAL COMPREHENSIVE INCOME	$ 104.5	$ 77.0	$ 233.3	$ 233.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2019	$ 56.6	$ 980.9	$ 1,518.5	$ (11.6)	$ 2,544.4
Common Stock Dividends			(21.3)		(21.3)
ASU 2016-13 Adoption			0.4		0.4
Net Income			92.3		92.3
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY -MARCH 31, 2020	56.6	980.9	1,589.9	(11.2)	2,616.2
Common Stock Dividends			(21.2)		(21.2)
Net Income			63.8		63.8
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2020	56.6	980.9	1,632.5	(10.8)	2,659.2
Common Stock Dividends			(21.2)		(21.2)
Net Income			76.7		76.7
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2020	$ 56.6	$ 980.9	$ 1,688.0	$ (10.5)	$ 2,715.0
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2020	$ 56.6	$ 980.9	$ 1,718.7	$ (7.0)	$ 2,749.2
Common Stock Dividends			(25.0)		(25.0)
Net Income			70.8		70.8
Other Comprehensive Income				0.5	0.5
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2021	56.6	980.9	1,764.5	(6.5)	2,795.5
Common Stock Dividends			(75.0)		(75.0)
Net Income			57.2		57.2
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2021	56.6	980.9	1,746.7	(6.2)	2,778.0
Common Stock Dividends			(75.0)		(75.0)
Net Income			104.1		104.1
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2021	$ 56.6	$ 980.9	$ 1,775.8	$ (5.8)	$ 2,807.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.2	$ 3.3
Advances to Affiliates	80.6	13.3
Accounts Receivable:		
Customers	39.8	44.0
Affiliated Companies	37.9	51.3
Miscellaneous	2.8	2.0
Allowance for Uncollectible Accounts	(0.3)	(0.3)
Total Accounts Receivable	80.2	97.0
Fuel	46.7	86.0
Materials and Supplies	172.2	175.8
Risk Management Assets	5.5	3.6
Accrued Tax Benefits	0.1	10.3
Regulatory Asset for Under-Recovered Fuel Costs	6.1	5.4
Prepayments and Other Current Assets	26.7	24.1
TOTAL CURRENT ASSETS	421.3	418.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,329.6	5,264.7
Transmission	1,749.4	1,696.4
Distribution	2,734.6	2,594.6
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	684.5	686.7
Construction Work in Progress	377.6	362.4
Total Property, Plant and Equipment	10,875.7	10,604.8
Accumulated Depreciation, Depletion and Amortization	3,811.9	3,552.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,063.8	7,052.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	436.1	404.8
Spent Nuclear Fuel and Decommissioning Trusts	3,609.8	3,306.7
Operating Lease Assets	154.7	218.1
Deferred Charges and Other Noncurrent Assets	219.5	237.6
TOTAL OTHER NONCURRENT ASSETS	4,420.1	4,167.2
TOTAL ASSETS	$ 11,905.2	$ 11,638.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2021 and December 31, 2020
(dollars in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 103.0
Accounts Payable:		
General	132.8	153.2
Affiliated Companies	86.2	80.5
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2021 and December 31, 2020 Amounts Include $78.7 and $75.7, Respectively, Related to DCC Fuel)	132.7	369.6
Risk Management Liabilities	2.5	0.1
Customer Deposits	42.4	41.7
Accrued Taxes	72.0	102.5
Accrued Interest	25.0	35.6
Obligations Under Operating Leases	86.2	85.6
Regulatory Liability for Over-Recovered Fuel Costs	3.5	20.8
Other Current Liabilities	104.2	111.9
TOTAL CURRENT LIABILITIES	687.5	1,104.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,098.4	2,660.3
Deferred Income Taxes	1,082.9	1,064.4
Regulatory Liabilities and Deferred Investment Tax Credits	2,201.2	2,041.9
Asset Retirement Obligations	1,869.2	1,812.9
Obligations Under Operating Leases	88.4	135.9
Deferred Credits and Other Noncurrent Liabilities	70.1	69.2
TOTAL NONCURRENT LIABILITIES	8,410.2	7,784.6
TOTAL LIABILITIES	9,097.7	8,889.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,775.8	1,718.7
Accumulated Other Comprehensive Income (Loss)	(5.8)	(7.0)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,807.5	2,749.2
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,905.2	$ 11,638.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	2020
OPERATING ACTIVITIES		
Net Income	$ 232.1	$ 232.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	328.7	303.6
Rockport Plant, Unit 2 Operating Lease Amortization	51.1	51.9
Deferred Income Taxes	(36.6)	(6.1)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(2.5)	21.3
Allowance for Equity Funds Used During Construction	(9.7)	(8.8)
Mark-to-Market of Risk Management Contracts	0.5	5.6
Amortization of Nuclear Fuel	61.9	67.2
Pension Contributions to Qualified Plan Trust	—	(6.4)
Deferred Fuel Over/Under-Recovery, Net	(18.0)	23.4
Change in Other Noncurrent Assets	7.3	40.8
Change in Other Noncurrent Liabilities	(10.2)	30.2
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	18.2	32.2
Fuel, Materials and Supplies	43.0	(15.4)
Accounts Payable	20.1	(0.9)
Accrued Taxes, Net	(20.3)	(84.4)
Rockport Plant, Unit 2 Operating Lease Payments	(36.9)	(36.9)
Other Current Assets	(0.7)	6.6
Other Current Liabilities	(28.0)	(59.1)
Net Cash Flows from Operating Activities	600.0	597.6
INVESTING ACTIVITIES		
Construction Expenditures	(370.2)	(409.1)
Change in Advances to Affiliates, Net	(67.3)	(0.1)
Purchases of Investment Securities	(1,586.3)	(1,290.0)
Sales of Investment Securities	1,556.6	1,257.1
Acquisitions of Nuclear Fuel	(63.2)	(68.4)
Other Investing Activities	12.9	8.3
Net Cash Flows Used for Investing Activities	(517.5)	(502.2)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	507.0	—
Change in Advances from Affiliates, Net	(103.0)	44.7
Retirement of Long-term Debt – Nonaffiliated	(307.2)	(71.1)
Principal Payments for Finance Lease Obligations	(4.9)	(4.8)
Dividends Paid on Common Stock	(175.0)	(63.7)
Other Financing Activities	0.5	0.3
Net Cash Flows Used for Financing Activities	(82.6)	(94.6)
Net Increase (Decrease) in Cash and Cash Equivalents	(0.1)	0.8
Cash and Cash Equivalents at Beginning of Period	3.3	2.0
Cash and Cash Equivalents at End of Period	$ 3.2	$ 2.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 93.9	$ 97.5
Net Cash Paid for Income Taxes	11.8	59.7
Noncash Acquisitions Under Finance Leases	3.1	1.9
Construction Expenditures Included in Current Liabilities as of September 30,	59.0	57.6
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	0.3	1.0
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.6	2.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions of KWhs)			
Retail:				
Residential	4,096	4,165	11,261	11,140
Commercial	4,112	3,781	11,282	10,454
Industrial	3,633	3,380	10,769	9,855
Miscellaneous	25	22	80	82
Total Retail (a)	11,866	11,348	33,392	31,531
Wholesale (b)	643	502	1,691	1,347
Total KWhs	12,509	11,850	35,083	32,878

(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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in degree days)			
Actual – Heating (a)	1	2	1,993	1,767
Normal – Heating (b)	5	6	2,071	2,086
Actual – Cooling (c)	787	809	1,148	1,126
Normal – Cooling (b)	689	682	996	986

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Ohio Power Company and Subsidiaries
Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Net Income
(in millions)

Third Quarter of 2020	$	59.0
Changes in Gross Margin:		
Retail Margins		15.1
Margins from Off-system Sales		(8.7)
Transmission Revenues		(2.3)
Other Revenues		7.8
Total Change in Gross Margin		11.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(6.1)
Depreciation and Amortization		(2.8)
Taxes Other Than Income Taxes		(8.2)
Interest Income		(0.2)
Carrying Costs Income		(0.2)
Allowance for Equity Funds Used During Construction		(2.6)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		(3.5)
Total Change in Expenses and Other		(23.7)
Income Tax Expense		9.2
Third Quarter of 2021	$	56.4

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

- **Retail Margins** increased $15 million primarily due to the following:
  - A $40 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $15 million increase related to various rider revenues. This increase was partially offset in Margins from Off-system Sales, Other Revenues, and other expense items below.
  - A $3 million increase in usage primarily from the industrial and commercial classes.

  These increases were partially offset by:
  - A $24 million decrease due to the ending of the Energy Efficiency and Peak Demand Rider in December 2020.This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $15 million decrease in revenues associated with the Universal Service Fund (USF).This decrease was offset in Other Operation and Maintenance expenses below.
- **Margins from Off-system Sales** decreased $9 million primarily due to the following:
  - A $19 million decrease in deferrals of OVEC costs. This decrease was offset in Retail Margins above and Other Revenues below.

  This decrease was partially offset by:
  - A $10 million increase in off-system sales at OVEC. This increase was offset in Retail Margins above and Other Revenues below.
- **Other Revenues** increased $8 million primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins and Margins from Off-system Sales above.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $6 million primarily due to the following:
  - A $34 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $5 million increase in recoverable distribution expenses primarily related to vegetation management. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $15 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset in Retail Margins above.
  - A $15 million decrease in energy efficiency/demand side management expenses. This decrease was partially offset within Retail Margins above.
  - A $5 million decrease in factored customer accounts receivable expenses primarily due to bad debt expenses and a current year adjustment to allowance for doubtful accounts.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $9 million primarily due to an unfavorable discrete adjustment recorded in 2020 that did not recur in 2021 and a decrease in pretax book income.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Ohio Power Company and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Net Income
(in millions)

Nine Months Ended September 30, 2020	$	215.0
Changes in Gross Margin:		
Retail Margins		92.1
Margins from Off-system Sales		(36.0)
Transmission Revenues		(4.6)
Other Revenues		20.8
Total Change in Gross Margin		72.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(38.6)
Depreciation and Amortization		(24.2)
Taxes Other Than Income Taxes		(28.4)
Interest Income		(0.3)
Carrying Costs Income		(0.2)
Allowance for Equity Funds Used During Construction		(1.7)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(7.8)
Total Change in Expenses and Other		(101.5)
Income Tax Expense		12.8
Nine Months Ended September 30, 2021	$	198.6

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

- **Retail Margins** increased $92 million primarily due to the following:
  - A $129 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $71 million increase related to various rider revenues. This increase was partially offset in Margins from Off-system Sales, Other Revenues, and other expense items below.
  - A $4 million increase in usage primarily from the commercial and industrial classes.

  These increases were partially offset by:
  - A $71 million decrease due to the ending of the Energy Efficiency and Peak Demand Rider in December 2020.This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $43 million decrease in revenues associated with the USF. This decrease was offset in Other Operation and Maintenance expenses below.
- **Margins from Off-system Sales** decreased $36 million primarily due to the following:
  - A $51 million decrease in deferrals of OVEC costs. This decrease was offset in Retail Margins above and Other Revenues below.

  This decrease was partially offset by:
  - A $16 million increase in off-system sales at OVEC. This increase was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** decreased $5 million primarily due to a decrease in net affiliated transmission expenses.
- **Other Revenues** increased $21 million primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $39 million primarily due to the following:
  - A $112 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $15 million increase in recoverable distribution expenses related to vegetation management. This increase was offset in Retail Margins above.
  - A $9 million increase in PJM expenses primarily related to the annual transmission formula rate true-up.
  - An $8 million increase in distribution maintenance expenses related to the annual major storm reserve true-up. This increase was offset in retail margins.

  These increases were partially offset by:
  - A $45 million decrease in energy efficiency/demand side management expenses. This decrease was partially offset within Retail Margins above.
  - A $43 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset in Retail Margins above.
  - A $19 million decrease in factored customer accounts receivable expenses primarily due to bad debt expenses and a current year adjustment to allowance for doubtful accounts.
- **Depreciation and Amortization** expenses increased $24 million primarily due to the following:
  - An $8 million increase in amortization of plant primarily related to capitalized software.
  - A $7 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $7 million increase in recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to the following:
  - A $23 million increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
  - A $3 million increase in excise taxes driven by increased metered KWh usage in 2021. This increase was offset in Retail Margins above.
- **Interest Expense** increased $8 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $13 million primarily due to an unfavorable discrete tax adjustment recorded during 2020 and a decrease in pretax book income.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
REVENUES				
Electricity, Transmission and Distribution	$ 761.0	$ 730.4	$ 2,167.8	$ 2,031.4
Sales to AEP Affiliates	4.3	8.3	21.9	33.0
Other Revenues	2.4	2.3	6.8	7.3
TOTAL REVENUES	767.7	741.0	2,196.5	2,071.7
EXPENSES				
Purchased Electricity for Resale	184.7	149.3	513.6	412.3
Purchased Electricity from AEP Affiliates	3.5	24.1	48.0	96.8
Other Operation	245.1	244.6	622.9	608.5
Maintenance	39.3	33.7	116.4	92.2
Depreciation and Amortization	76.9	74.1	228.6	204.4
Taxes Other Than Income Taxes	126.0	117.8	366.2	337.8
TOTAL EXPENSES	675.5	643.6	1,895.7	1,752.0
OPERATING INCOME	92.2	97.4	300.8	319.7
Other Income (Expense):				
Interest Income	0.2	0.4	0.5	0.8
Carrying Costs Income	0.1	0.3	1.1	1.3
Allowance for Equity Funds Used During Construction	2.0	4.6	7.6	9.3
Non-Service Cost Components of Net Periodic Benefit Cost	3.7	3.8	11.0	11.3
Interest Expense	(32.9)	(29.4)	(96.2)	(88.4)
INCOME BEFORE INCOME TAX EXPENSE	65.3	77.1	224.8	254.0
Income Tax Expense	8.9	18.1	26.2	39.0
NET INCOME	$ 56.4	$ 59.0	$ 198.6	$ 215.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 321.2	$ 838.8	$ 1,348.5	$ 2,508.5
Common Stock Dividends			(21.9)	(21.9)
ASU 2016-13 Adoption			0.3	0.3
Net Income			75.1	75.1
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	321.2	838.8	1,402.0	2,562.0
Common Stock Dividends			(21.9)	(21.9)
Net Income			80.9	80.9
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2020	321.2	838.8	1,461.0	2,621.0
Common Stock Dividends			(21.8)	(21.8)
Net Income			59.0	59.0
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2020	$ 321.2	$ 838.8	$ 1,498.2	$ 2,658.2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 321.2	$ 838.8	$ 1,532.7	$ 2,692.7
Common Stock Dividends			(21.9)	(21.9)
Net Income			68.2	68.2
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	321.2	838.8	1,579.0	2,739.0
Common Stock Dividends			(21.9)	(21.9)
Net Income			74.0	74.0
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2021	321.2	838.8	1,631.1	2,791.1
Common Stock Dividends			(28.1)	(28.1)
Net Income			56.4	56.4
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2021	$ 321.2	$ 838.8	$ 1,659.4	$ 2,819.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6.8	$ 7.4
Advances to Affiliates	622.9	—
Accounts Receivable:		
Customers	31.0	50.0
Affiliated Companies	64.7	65.1
Accrued Unbilled Revenues	15.3	14.8
Miscellaneous	5.8	3.9
Allowance for Uncollectible Accounts	(0.6)	(0.6)
Total Accounts Receivable	116.2	133.2
Materials and Supplies	70.9	66.9
Renewable Energy Credits	31.1	29.5
Prepayments and Other Current Assets	29.6	19.3
TOTAL CURRENT ASSETS	877.5	256.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,936.3	2,831.9
Distribution	5,989.2	5,708.3
Other Property, Plant and Equipment	979.9	899.6
Construction Work in Progress	331.7	362.3
Total Property, Plant and Equipment	10,237.1	9,802.1
Accumulated Depreciation and Amortization	2,438.7	2,350.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,798.4	7,452.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	343.8	385.8
Operating Lease Assets	84.2	92.0
Deferred Charges and Other Noncurrent Assets	292.4	524.2
TOTAL OTHER NONCURRENT ASSETS	720.4	1,002.0
TOTAL ASSETS	$ 9,396.3	$ 8,710.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2021 and December 31, 2020
(Unaudited)

	September 30, 2021	December 31, 2020
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 259.2
Accounts Payable:		
General	169.0	181.0
Affiliated Companies	101.5	118.4
Long-term Debt Due Within One Year – Nonaffiliated	500.1	500.1
Risk Management Liabilities	3.5	8.7
Customer Deposits	123.5	55.1
Accrued Taxes	344.8	631.0
Obligations Under Operating Leases	13.1	13.1
Other Current Liabilities	149.6	139.6
TOTAL CURRENT LIABILITIES	1,405.1	1,906.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,968.0	1,930.1
Long-term Risk Management Liabilities	86.9	101.6
Deferred Income Taxes	1,010.7	955.1
Regulatory Liabilities and Deferred Investment Tax Credits	995.7	1,005.2
Obligations Under Operating Leases	71.6	79.5
Deferred Credits and Other Noncurrent Liabilities	38.9	40.0
TOTAL NONCURRENT LIABILITIES	5,171.8	4,111.5
TOTAL LIABILITIES	6,576.9	6,017.7
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,659.4	1,532.7
TOTAL COMMON SHAREHOLDER'S EQUITY	2,819.4	2,692.7
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 9,396.3	$ 8,710.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	2020
OPERATING ACTIVITIES		
Net Income	$ 198.6	$ 215.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	228.6	204.4
Deferred Income Taxes	29.3	35.6
Allowance for Equity Funds Used During Construction	(7.6)	(9.3)
Mark-to-Market of Risk Management Contracts	(19.9)	9.7
Property Taxes	234.9	225.1
Change in Other Noncurrent Assets	(1.1)	(93.8)
Change in Other Noncurrent Liabilities	4.6	(58.3)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	20.7	33.4
Materials and Supplies	(0.6)	(19.8)
Accounts Payable	(19.1)	(19.9)
Customer Deposits	68.4	12.4
Accrued Taxes, Net	(289.7)	(266.2)
Other Current Assets	(7.8)	(2.5)
Other Current Liabilities	5.8	(35.7)
Net Cash Flows from Operating Activities	445.1	230.1
INVESTING ACTIVITIES		
Construction Expenditures	(536.6)	(604.6)
Change in Advances to Affiliates, Net	(622.9)	—
Other Investing Activities	10.7	14.1
Net Cash Flows Used for Investing Activities	(1,148.8)	(590.5)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	1,037.5	347.0
Change in Advances from Affiliates, Net	(259.2)	84.9
Retirement of Long-term Debt – Nonaffiliated	(0.1)	(0.1)
Principal Payments for Finance Lease Obligations	(3.7)	(3.5)
Dividends Paid on Common Stock	(71.9)	(65.6)
Other Financing Activities	0.5	0.6
Net Cash Flows from Financing Activities	703.1	363.3
Net Increase (Decrease) in Cash and Cash Equivalents	(0.6)	2.9
Cash and Cash Equivalents at Beginning of Period	7.4	3.7
Cash and Cash Equivalents at End of Period	$ 6.8	$ 6.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 78.6	$ 69.7
Net Cash Paid (Received) for Income Taxes	0.3	(6.0)
Noncash Acquisitions Under Finance Leases	1.4	5.2
Construction Expenditures Included in Current Liabilities as of September 30,	66.5	75.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

PUBLIC SERVICE COMPANY OF OKLAHOMA

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions of KWhs)			
Retail:				
Residential	2,179	2,019	5,068	4,838
Commercial	1,476	1,358	3,781	3,549
Industrial	1,566	1,461	4,383	4,299
Miscellaneous	355	347	935	912
Total Retail	5,576	5,185	14,167	13,598
Wholesale	162	130	350	261
Total KWhs	5,738	5,315	14,517	13,859

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in degree days)			
Actual – Heating (a)	—	1	1,195	874
Normal – Heating (b)	1	1	1,078	1,078
Actual – Cooling (c)	1,491	1,274	2,075	1,979
Normal – Cooling (b)	1,404	1,412	2,079	2,088

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Public Service Company of Oklahoma
Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Net Income
(in millions)

Third Quarter of 2020	$	80.3
Changes in Gross Margin:		
Retail Margins (a)		29.7
Margins from Off-system Sales		(0.4)
Transmission Revenues		2.1
Other Revenues		(0.1)
Total Change in Gross Margin		31.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(11.9)
Depreciation and Amortization		(8.8)
Interest Income		1.3
Allowance for Equity Funds Used During Construction		(0.8)
Interest Expense		(1.6)
Total Change in Expenses and Other		(21.8)
Income Tax Expense		3.4
Third Quarter of 2021	$	93.2

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

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

- **Retail Margins** increased $30 million primarily due to the following:
  - A $22 million increase in revenue from rate riders. This increase was partially offset in other expense items below.
  - A $13 million increase in weather-related usage primarily due to a 17% increase in cooling degree days.
  - A $3 million increase in weather-normalized retail margins primarily in the commercial class.

  These increases were partially offset by:
  - A $9 million increase in fuel expense due to NCWF PTC benefits provided to customers.This decrease was offset in Income Tax Expense below.

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

- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
  - A $10 million increase in recoverable SPP transmission expense. This increase was partially offset in Retail Margins above.
- **Depreciation and Amortization** increased $9 million primarily due to a higher depreciable base and the timing of refunds to customers under rate rider mechanisms.
- **Income Tax Expense** decreased $3 million primarily due to an increase in PTC, partially offset by an increase in pretax book income.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Public Service Company of Oklahoma
Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Net Income
(in millions)

Nine Months Ended September 30, 2020	$	116.4
Changes in Gross Margin:		
Retail Margins (a)		46.8
Margin from Off-system Sales		(0.6)
Transmission Revenues		5.3
Other Revenues		(5.7)
Total Change in Gross Margin		45.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(13.4)
Depreciation and Amortization		(19.2)
Taxes Other Than Income Taxes		(1.3)
Interest Income		2.9
Allowance for Equity Funds Used During Construction		(1.7)
Non-Service Cost Components of Net Periodic Benefit Cost		0.1
Interest Expense		1.2
Total Change in Expenses and Other		(31.4)
Income Tax Expense		5.8
Nine Months Ended September 30, 2021	$	136.6

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

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

- **Retail Margins** increased $47 million primarily due to the following:
  - A $41 million increase in revenue from rate riders. This increase was partially offset in other expense items below.
  - A $9 million increase in weather-related usage primarily due to a 37% increase in heating degree days and a 5% increase in cooling degree days.
  - An $8 million increase in weather-normalized retail margins primarily in the commercial and residential classes.

  These increases were partially offset by:
  - An $11 million increase in fuel expense due to NCWF PTC benefits provided to customers.This decrease was offset in Income Tax Expense below.
- **Transmission Revenues** increased $5 million primarily due to the following:
  - A $3 million increase due to increased transmission investments.
  - A $2 million increase due to the annual transmission formula rate true-up.
- **Other Revenues** decreased $6 million primarily due to lower business development revenue. This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $13 million primarily due to the following:
  - A $19 million increase in transmission expenses primarily due to a $13 million increase in recoverable SPP transmission expense and a $5 million increase as a result of the annual transmission formula rate true-up. These increases were partially offset in Retail Margins above.
  - A $3 million increase due to the prior year capitalization of previously expensed North Central Wind Energy Facilities costs.

These increases were partially offset by:

- A $5 million decrease in distribution expenses primarily due to a decrease in overhead line maintenance.
- A $5 million decrease in business development expenses. This decrease was partially offset in Other Revenues above.

- **Depreciation and Amortization** expenses increased $19 million primarily due to a higher depreciable base and the timing of refunds to customers under rate rider mechanisms.
- **Income Tax Expense** decreased $6 million primarily due to an increase in PTC, partially offset by an increase in pretax book income.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
REVENUES				
Electric Generation, Transmission and Distribution	$ 481.3	$ 379.8	$ 1,117.4	$ 976.3
Sales to AEP Affiliates	1.0	1.4	3.1	3.8
Other Revenues	1.5	1.0	3.9	8.0
TOTAL REVENUES	483.8	382.2	1,124.4	988.1
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	195.9	125.6	440.8	350.3
Other Operation	102.3	91.7	262.7	248.5
Maintenance	21.2	19.9	68.1	68.9
Depreciation and Amortization	48.9	40.1	149.0	129.8
Taxes Other Than Income Taxes	12.1	12.1	37.1	35.8
TOTAL EXPENSES	380.4	289.4	957.7	833.3
OPERATING INCOME	103.4	92.8	166.7	154.8
Other Income (Expense):				
Interest Income	1.3	—	3.0	0.1
Allowance for Equity Funds Used During Construction	0.5	1.3	1.5	3.2
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.1	6.4	6.3
Interest Expense	(16.2)	(14.6)	(44.7)	(45.9)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	91.1	81.6	132.9	118.5
Income Tax Expense (Benefit)	(2.1)	1.3	(3.7)	2.1
NET INCOME	$ 93.2	$ 80.3	$ 136.6	$ 116.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
Net Income	$ 93.2	$ 80.3	$ 136.6	$ 116.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $0 and $(0.2) for the Nine Months Ended September 30, 2021 and 2020, Respectively.	—	(0.3)	(0.1)	(0.8)
TOTAL COMPREHENSIVE INCOME	$ 93.2	$ 80.0	$ 136.5	$ 115.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 157.2	$ 364.0	$ 851.0	$ 1.1	$ 1,373.3
SU 2016-13 Adoption			0.3		0.3
et Loss			(10.3)		(10.3)
her Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	157.2	364.0	841.0	0.9	1,363.1
et Income			46.4		46.4
her Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2020	157.2	364.0	887.4	0.6	1,409.2
et Income			80.3		80.3
her Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2020	$ 157.2	$ 364.0	$ 967.7	$ 0.3	$ 1,489.2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 157.2	$ 414.0	$ 974.3	$ 0.1	$ 1,545.6
pital Contribution from Parent		425.0			425.0
et Loss			(2.7)		(2.7)
her Comprehensive Loss				(0.1)	(0.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	157.2	839.0	971.6	—	1,967.8
pital Contribution from Parent		200.0			200.0
mmon Stock Dividends			(10.0)		(10.0)
et Income			46.1		46.1
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2021	157.2	1,039.0	1,007.7	—	2,203.9
mmon Stock Dividends			(10.0)		(10.0)
et Income			93.2		93.2
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2021	$ 157.2	$ 1,039.0	$ 1,090.9	—	$ 2,287.1

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.6	$ 2.6
Advances to Affiliates	59.5	—
Accounts Receivable:		
Customers	29.7	30.8
Affiliated Companies	31.7	15.6
Miscellaneous	0.4	2.0
Total Accounts Receivable	61.8	48.4
Fuel	7.6	17.9
Materials and Supplies	54.4	54.0
Risk Management Assets	18.5	10.3
Accrued Tax Benefits	35.7	10.9
Regulatory Asset for Under-Recovered Fuel Costs	133.4	30.1
Prepayments and Other Current Assets	13.1	7.1
TOTAL CURRENT ASSETS	387.6	181.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,795.2	1,480.7
Transmission	1,095.9	1,069.9
Distribution	2,959.7	2,853.0
Other Property, Plant and Equipment	427.8	393.3
Construction Work in Progress	127.7	128.7
Total Property, Plant and Equipment	6,406.3	5,925.6
Accumulated Depreciation and Amortization	1,682.6	1,605.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,723.7	4,320.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,052.3	375.0
Employee Benefits and Pension Assets	66.2	65.8
Operating Lease Assets	70.4	42.6
Deferred Charges and Other Noncurrent Assets	18.9	6.0
TOTAL OTHER NONCURRENT ASSETS	1,207.8	489.4
TOTAL ASSETS	$ 6,319.1	$ 4,990.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2021 and December 31, 2020
(Unaudited)

	September 30, 2021	December 31, 2020
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 155.4
Accounts Payable:		
General	146.4	107.0
Affiliated Companies	32.0	43.4
Long-term Debt Due Within One Year – Nonaffiliated	0.5	0.5
Customer Deposits	54.0	54.8
Accrued Taxes	60.9	26.8
Obligations Under Operating Leases	6.9	6.5
Other Current Liabilities	67.9	84.2
TOTAL CURRENT LIABILITIES	368.6	478.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,912.8	1,373.3
Deferred Income Taxes	764.0	688.5
Regulatory Liabilities and Deferred Investment Tax Credits	846.2	802.2
Asset Retirement Obligations	55.0	45.7
Obligations Under Operating Leases	63.7	36.2
Deferred Credits and Other Noncurrent Liabilities	21.7	20.6
TOTAL NONCURRENT LIABILITIES	3,663.4	2,966.5
TOTAL LIABILITIES	4,032.0	3,445.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	1,039.0	414.0
Retained Earnings	1,090.9	974.3
Accumulated Other Comprehensive Income (Loss)	—	0.1
TOTAL COMMON SHAREHOLDER'S EQUITY	2,287.1	1,545.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 6,319.1	$ 4,990.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2021	2020
OPERATING ACTIVITIES		
Net Income	$ 136.6	$ 116.4
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	149.0	129.8
Deferred Income Taxes	109.8	(3.2)
Allowance for Equity Funds Used During Construction	(1.5)	(3.2)
Mark-to-Market of Risk Management Contracts	(8.2)	(0.3)
Property Taxes	(10.9)	(10.6)
Deferred Fuel Over/Under-Recovery, Net	(776.4)	(46.6)
Change in Other Noncurrent Assets	(12.8)	(7.2)
Change in Other Noncurrent Liabilities	4.5	6.1
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(13.4)	(5.6)
Fuel, Materials and Supplies	9.9	(17.2)
Accounts Payable	16.4	(26.1)
Accrued Taxes, Net	9.3	36.9
Other Current Assets	(5.9)	(0.1)
Other Current Liabilities	(18.4)	(16.4)
Net Cash Flows from (Used for) Operating Activities	(412.0)	152.7
INVESTING ACTIVITIES		
Construction Expenditures	(219.6)	(256.4)
Change in Advances to Affiliates, Net	(59.5)	38.8
Acquisition of the North Central Wind Energy Facilities	(297.0)	—
Other Investing Activities	1.9	3.9
Net Cash Flows Used for Investing Activities	(574.2)	(213.7)
FINANCING ACTIVITIES		
Capital Contributions from Parent	625.0	—
Issuance of Long-term Debt – Nonaffiliated	1,290.0	—
Change in Advances from Affiliates, Net	(155.4)	77.8
Retirement of Long-term Debt – Nonaffiliated	(750.4)	(13.0)
Principal Payments for Finance Lease Obligations	(2.5)	(2.7)
Dividends Paid on Common Stock	(20.0)	—
Other Financing Activities	0.5	0.4
Net Cash Flows from Financing Activities	987.2	62.5
Net Increase in Cash and Cash Equivalents	1.0	1.5
Cash and Cash Equivalents at Beginning of Period	2.6	1.5
Cash and Cash Equivalents at End of Period	$ 3.6	$ 3.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 42.9	$ 45.5
Net Cash Paid (Received) for Income Taxes	(101.2)	(9.5)
Noncash Acquisitions Under Finance Leases	3.1	3.0
Construction Expenditures Included in Current Liabilities as of September 30,	44.2	23.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
	(in millions of KWhs)			
Retail:				
Residential	1,999	1,950	4,973	4,702
Commercial	1,616	1,552	4,221	4,016
Industrial	1,203	1,185	3,468	3,614
Miscellaneous	19	19	58	59
Total Retail	4,837	4,706	12,720	12,391
Wholesale	2,170	1,571	5,103	4,081
Total KWhs	7,007	6,277	17,823	16,472

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	**2020**	**2021**	**2020**
	(in degree days)			
Actual – Heating (a)	—	—	789	522
Normal – Heating (b)	1	1	723	724
Actual – Cooling (c)	1,478	1,308	2,251	2,051
Normal – Cooling (b)	1,416	1,420	2,195	2,200

(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.

Third Quarter of 2021 Compared to Third Quarter of 2020

Reconciliation of Third Quarter of 2020 to Third Quarter of 2021
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2020	$	87.9
Changes in Gross Margin:		
Retail Margins (a)		16.2
Margins from Off-system Sales		0.1
Transmission Revenues		8.1
Other Revenues		0.7
Total Change in Gross Margin		25.1
Changes in Expenses and Other:		
Other Operation and Maintenance		2.1
Depreciation and Amortization		(6.3)
Taxes Other Than Income Taxes		(2.2)
Interest Income		2.2
Allowance for Equity Funds Used During Construction		(2.0)
Interest Expense		(2.4)
Total Change in Expenses and Other		(8.6)
Income Tax Expense		4.5
Equity Earnings of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interest		(0.3)
Third Quarter of 2021	$	108.9

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

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

- **Retail Margins** increased $16 million primarily due to the following:
  - A $12 million increase in weather-related usage primarily due to a 13% increase in cooling degree days.
  - A $2 million increase in recoverable fuel costs primarily due to timing of recovery.
- **Transmission Revenues** increased $8 million primarily due to increased load and transmission investment.

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

- **Other Operation and Maintenance** expenses decreased $2 million primarily due to the following:
  - A $6 million decrease in administrative & general expenses and employee-related expenses.

  This decrease was partially offset by:
  - A $5 million increase in transmission expense primarily due to increased load.
- **Depreciation and Amortization** expenses increased $6 million primarily due to a higher depreciable base.
- **Income Tax Expense** decreased $5 million primarily due to the following:
  - A $10 million decrease in state income taxes.
  - A $6 million increase in PTC.

  The overall decrease was partially offset by:
  - A $3 million increase due to an increase in pretax book income.
  - A $3 million decrease in parent company loss benefit.
  - A $2 million decrease in amortization of Excess ADIT, partially offset in Retail Margins above.
  - A $2 million discrete tax adjustment recognized in 2021.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020

Reconciliation of Nine Months Ended September 30, 2020 to Nine Months Ended September 30, 2021
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2020	$	161.8
Changes in Gross Margin:		
Retail Margins (a)		62.4
Margins from Off-system Sales		21.2
Transmission Revenues		5.4
Other Revenues		1.9
Total Change in Gross Margin		90.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(13.9)
Depreciation and Amortization		(13.5)
Taxes Other Than Income Taxes		(12.0)
Interest Income		5.2
Allowance for Equity Funds Used During Construction		(0.3)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		(3.3)
Total Change in Expenses and Other		(37.9)
Income Tax Expense		(6.5)
Equity Earnings of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interest		(0.5)
Nine Months Ended September 30, 2021	$	208.1

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

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

- **Retail Margins** increased $62 million primarily due to the following:
  - A $25 million increase in weather-related usage primarily due to a 51% increase in heating degree days and a 10% increase in cooling degree days.
  - A $13 million increase in municipal and cooperative revenues primarily due to the February 2021 severe winter weather event.
  - A $10 million increase in recoverable fuel costs primarily due to timing of recovery.
  - A $6 million increase in municipal and cooperative revenues due to the annual generation formula rate true-up.
  - A $6 million increase due to a decrease in the return of Excess ADIT benefits to customers. This increase was offset in Income Tax Expense below.
- **Margins from Off-system Sales** increased $21 million primarily due to Turk Plant merchant sales as a result of the February 2021 severe winter weather event.
- **Transmission Revenues** increased $5 million primarily due to the following:
  - A $12 million increase due to increased load and transmission investment.

  This increase was partially offset by:
  - A $6 million decrease due to the annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses increased $14 million primarily due to the following:
  - A $19 million increase in transmission expense primarily due to a $10 million increase as a result of the annual formula rate true-up and a $12 million increase in NITS expense due to increased load.
  - A $5 million increase due to the prior year capitalization of previously expensed North Central Wind Energy Facilities costs.

  These increases were partially offset by:
  - A $6 million decrease in administrative & general expenses and employee-related expenses.
  - A $2 million decrease in overhead line maintenance primarily related to storm restoration.
- **Depreciation and Amortization** expenses increased $14 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to increased property taxes resulting from the expiration of the Louisiana Industrial Tax Exemption related to Stall Plant.
- **Interest Income** increased $5 million primarily related to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event.
- **Interest Expense** increased $3 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $7 million primarily due to the following:
  - An $11 million increase due to an increase in pretax book income.
  - A $10 million decrease in amortization of Excess ADIT, partially offset in Retail Margins above.
  - A $3 million decrease in parent company loss benefit.
  - A $2 million decrease in flow through tax benefits.
  - A $2 million discrete tax adjustment recognized in 2021.

  The overall increase was partially offset by:
  - A $12 million decrease in state income tax expense.
  - A $10 million increase in PTC.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
REVENUES				
Electric Generation, Transmission and Distribution	$ 570.1	$ 505.7	$ 1,596.6	$ 1,284.3
Sales to AEP Affiliates	13.5	10.9	32.2	31.5
Other Revenues	0.5	0.7	1.5	2.4
TOTAL REVENUES	584.1	517.3	1,630.3	1,318.2
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	214.4	172.7	652.7	431.5
Other Operation	91.7	96.8	270.6	259.0
Maintenance	33.7	30.7	99.5	97.2
Depreciation and Amortization	74.8	68.5	217.4	203.9
Taxes Other Than Income Taxes	28.9	26.7	89.0	77.0
TOTAL EXPENSES	443.5	395.4	1,329.2	1,068.6
OPERATING INCOME	140.6	121.9	301.1	249.6
Other Income (Expense):				
Interest Income	2.8	0.6	6.9	1.7
Allowance for Equity Funds Used During Construction	1.4	3.4	5.4	5.7
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.1	6.2	6.3
Interest Expense	(31.7)	(29.3)	(92.4)	(89.1)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	115.2	98.7	227.2	174.2
Income Tax Expense	6.3	10.8	19.0	12.5
Equity Earnings of Unconsolidated Subsidiary	1.0	0.7	2.5	2.2
NET INCOME	109.9	88.6	210.7	163.9
Net Income Attributable to Noncontrolling Interest	1.0	0.7	2.6	2.1
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 108.9	$ 87.9	$ 208.1	$ 161.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net Income	$ 109.9	$ 88.6	$ 210.7	$ 163.9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2021 and 2020, Respectively, and $0.3 and $0.3 for the Nine Months Ended September 30, 2021 and 2020, Respectively	0.3	0.4	1.1	1.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2021 and 2020, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2021 and 2020, Respectively	(0.4)	(0.4)	(1.2)	(1.1)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.1)	—	(0.1)	—
TOTAL COMPREHENSIVE INCOME	109.8	88.6	210.6	163.9
Total Comprehensive Income Attributable to Noncontrolling Interest	1.0	0.7	2.6	2.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 108.8	$ 87.9	$ 208.0	$ 161.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2019	$ 135.7	$ 676.6	$ 1,629.5	$ (1.3)	$ 0.6	$ 2,441.1
Common Stock Dividends – Nonaffiliated					(0.7)	(0.7)
ASU 2016-13 Adoption			1.6			1.6
Net Income			15.1		1.0	16.1
TOTAL EQUITY – MARCH 31, 2020	135.7	676.6	1,646.2	(1.3)	0.9	2,458.1
Common Stock Dividends – Nonaffiliated					(1.2)	(1.2)
Net Income			58.8		0.4	59.2
TOTAL EQUITY – JUNE 30, 2020	135.7	676.6	1,705.0	(1.3)	0.1	2,516.1
Reverse Common Stock Split	(135.6)	135.6				—
Common Stock Dividends – Nonaffiliated					(0.4)	(0.4)
Net Income			87.9		0.7	88.6
TOTAL EQUITY – SEPTEMBER 30, 2020	$ 0.1	$ 812.2	$ 1,792.9	$ (1.3)	$ 0.4	$ 2,604.3
TOTAL EQUITY – DECEMBER 31, 2020	$ 0.1	$ 812.2	$ 1,811.9	$ 1.9	$ 1.6	$ 2,627.7
Capital Contribution from Parent		100.0				100.0
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			62.4		1.0	63.4
TOTAL EQUITY – MARCH 31, 2021	0.1	912.2	1,874.3	1.9	1.6	2,790.1
Capital Contribution from Parent		75.0				75.0
Common Stock Dividends – Nonaffiliated					(0.6)	(0.6)
Net Income			36.8		0.6	37.4
TOTAL EQUITY – JUNE 30, 2021	0.1	987.2	1,911.1	1.9	1.6	2,901.9
Capital Contribution from Parent		105.0				105.0
Common Stock Dividends – Nonaffiliated					(2.2)	(2.2)
Net Income			108.9		1.0	109.9
Other Comprehensive Loss				(0.1)		(0.1)
TOTAL EQUITY – SEPTEMBER 30, 2021	$ 0.1	$ 1,092.2	$ 2,020.0	$ 1.8	$ 0.4	$ 3,114.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2021 and December 31, 2020
(in millions)
(Unaudited)

	September 30, 2021	December 31, 2020
CURRENT ASSETS		
Cash and Cash Equivalents (September 30, 2021 and December 31, 2020 Amounts Include $41 and $10.1, Respectively, Related to Sabine)	$ 45.0	$ 13.2
Advances to Affiliates	2.1	2.1
Accounts Receivable:		
Customers	76.2	27.1
Affiliated Companies	35.6	25.1
Miscellaneous	23.3	12.7
Total Accounts Receivable	135.1	64.9
Fuel (September 30, 2021 and December 31, 2020 Amounts Include $6.7 and $35.2, Respectively, Related to Sabine)	95.4	191.1
Materials and Supplies (September 30, 2021 and December 31, 2020 Amounts Include $15.9 and $23.3, Respectively, Related to Sabine)	86.8	95.8
Risk Management Assets	17.5	3.2
Accrued Tax Benefits	19.8	29.9
Regulatory Asset for Under-Recovered Fuel Costs	38.7	2.6
Prepayments and Other Current Assets	20.8	25.2
TOTAL CURRENT ASSETS	461.2	428.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,065.5	4,681.4
Transmission	2,264.6	2,165.7
Distribution	2,499.2	2,382.5
Other Property, Plant and Equipment (September 30, 2021 and December 31, 2020 Amounts Include $220.2 and $223.7, Respectively, Related to Sabine)	817.6	788.8
Construction Work in Progress	195.5	228.3
Total Property, Plant and Equipment	10,842.4	10,246.7
Accumulated Depreciation and Amortization (September 30, 2021 and December 31, 2020 Amounts Include $156.7 and $126.5, Respectively, Related to Sabine)	3,478.5	3,158.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,363.9	7,088.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,068.0	403.1
Long-term Risk Management Assets	2.1	—
Deferred Charges and Other Noncurrent Assets	277.3	234.8
TOTAL OTHER NONCURRENT ASSETS	1,347.4	637.9
TOTAL ASSETS	$ 9,172.5	$ 8,154.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2021 and December 31, 2020
(Unaudited)

	September 30, 2021	December 31, 2020
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 122.9	$ 124.6
Accounts Payable:		
General	114.7	135.9
Affiliated Companies	43.4	43.0
Short-term Debt – Nonaffiliated	—	35.0
Long-term Debt Due Within One Year – Nonaffiliated	381.2	106.2
Risk Management Liabilities	—	0.7
Customer Deposits	60.7	61.3
Accrued Taxes	103.1	41.0
Accrued Interest	23.0	34.6
Obligations Under Operating Leases	8.3	7.9
Other Current Liabilities	119.6	173.4
TOTAL CURRENT LIABILITIES	976.9	763.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,748.7	2,530.2
Long-term Risk Management Liabilities	—	1.0
Deferred Income Taxes	1,067.6	1,017.6
Regulatory Liabilities and Deferred Investment Tax Credits	879.8	863.4
Asset Retirement Obligations	193.4	193.7
Employee Benefits and Pension Obligations	23.8	18.6
Obligations Under Operating Leases	79.2	44.1
Deferred Credits and Other Noncurrent Liabilities	88.6	94.2
TOTAL NONCURRENT LIABILITIES	5,081.1	4,762.8
TOTAL LIABILITIES	6,058.0	5,526.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	0.1	0.1
Paid-in Capital	1,092.2	812.2
Retained Earnings	2,020.0	1,811.9
Accumulated Other Comprehensive Income (Loss)	1.8	1.9
TOTAL COMMON SHAREHOLDER'S EQUITY	3,114.1	2,626.1
Noncontrolling Interest	0.4	1.6
TOTAL EQUITY	3,114.5	2,627.7
TOTAL LIABILITIES AND EQUITY	$ 9,172.5	$ 8,154.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2021 and 2020
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2021	2020
OPERATING ACTIVITIES		
Net Income	$ 210.7	$ 163.9
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	217.4	203.9
Deferred Income Taxes	22.5	(0.3)
Allowance for Equity Funds Used During Construction	(5.4)	(5.7)
Mark-to-Market of Risk Management Contracts	(18.1)	(2.3)
Pension Contributions to Qualified Plan Trust	—	(8.9)
Property Taxes	(20.0)	(16.5)
Deferred Fuel Over/Under-Recovery, Net	(506.8)	16.3
Change in Regulatory Assets	(91.5)	(64.5)
Change in Other Noncurrent Assets	38.3	3.2
Change in Other Noncurrent Liabilities	40.0	21.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(70.2)	8.0
Fuel, Materials and Supplies	115.1	(70.9)
Accounts Payable	(21.1)	88.0
Accrued Taxes, Net	72.2	46.6
Other Current Assets	4.2	1.3
Other Current Liabilities	(48.2)	(50.3)
Net Cash Flows from (Used for) Operating Activities	(60.9)	332.8
INVESTING ACTIVITIES		
Construction Expenditures	(277.2)	(319.5)
Acquisition of the North Central Wind Energy Facilities	(355.8)	—
Other Investing Activities	2.1	4.8
Net Cash Flows Used for Investing Activities	(630.9)	(314.7)
FINANCING ACTIVITIES		
Capital Contribution from Parent	280.0	—
Issuance of Long-term Debt – Nonaffiliated	496.4	—
Change in Short-term Debt – Nonaffiliated	(35.0)	23.7
Change in Advances from Affiliates, Net	(1.7)	11.9
Retirement of Long-term Debt – Nonaffiliated	(4.7)	(19.7)
Principal Payments for Finance Lease Obligations	(8.1)	(8.0)
Dividends Paid on Common Stock – Nonaffiliated	(3.8)	(2.3)
Other Financing Activities	0.5	0.3
Net Cash Flows from Financing Activities	723.6	5.9
Net Increase in Cash and Cash Equivalents	31.8	24.0
Cash and Cash Equivalents at Beginning of Period	13.2	1.6
Cash and Cash Equivalents at End of Period	$ 45.0	$ 25.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 98.0	$ 95.2
Net Cash Paid (Received) for Income Taxes	(11.3)	11.9
Noncash Acquisitions Under Finance Leases	4.4	5.9
Construction Expenditures Included in Current Liabilities as of September 30,	46.8	50.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 138.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and nine months ended September 30, 2021 is not necessarily indicative of results that may be expected for the year ending December 31, 2021. The condensed financial statements are unaudited and should be read in conjunction with the audited 2020 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 25, 2021.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Three Months Ended September 30, 2021 (in millions, except per share data)	$/share	2020	$/share
Earnings Attributable to AEP Common Shareholders	$ 796.0		$ 748.6	
Weighted-Average Number of Basic AEP Common Shares Outstanding	501.2	$ 1.59	496.2	$ 1.51
Weighted-Average Dilutive Effect of Stock-Based Awards	1.4	(0.01)	1.3	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	502.6	$ 1.58	497.5	$ 1.50

	Nine Months Ended September 30, 2021 (in millions, except per share data)	$/share	2020	$/share
Earnings Attributable to AEP Common Shareholders	$ 1,949.2		$ 1,764.6	
Weighted-Average Number of Basic AEP Common Shares Outstanding	499.4	$ 3.90	495.5	$ 3.56
Weighted-Average Dilutive Effect of Stock-Based Awards	1.2	(0.01)	1.4	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	500.6	$ 3.89	496.9	$ 3.55

Equity Units are potentially dilutive securities but were excluded from the calculation of diluted EPS for the three and nine months ended September 30, 2021 and 2020, as the dilutive stock price thresholds were not met. See Note 12 - Financing Activities for more information related to Equity Units.

There were 377 thousand and 0 antidilutive shares outstanding as of September 30, 2021 and 2020, respectively. The antidilutive shares were excluded from the calculation of diluted EPS.

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	September 30, 2021		
	AEP	AEP Texas	APCo
	(in millions)		
Cash and Cash Equivalents	$ 1,372.7	$ 0.1	$ 5.0
Restricted Cash	54.0	43.9	10.1
Total Cash, Cash Equivalents and Restricted Cash	$ 1,426.7	$ 44.0	$ 15.1

	December 31, 2020		
	AEP	AEP Texas	APCo
	(in millions)		
Cash and Cash Equivalents	$ 392.7	$ 0.1	$ 5.8
Restricted Cash	45.6	28.7	16.9
Total Cash, Cash Equivalents and Restricted Cash	$ 438.3	$ 28.8	$ 22.7

2. <u>NEW ACCOUNTING STANDARDS</u>

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

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. There are no new standards expected to have a material impact on the Registrants' financial statements.

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional information.

AEP

	Cash Flow Hedges		Pension	
Three Months Ended September 30, 2021	**Commodity**	**Interest Rate**	**and OPEB**	**Total**
		(in millions)		
Balance in AOCI as of June 30, 2021	$ 110.3	$ (32.2)	$ 18.9	$ 97.0
Change in Fair Value Recognized in AOCI	220.8	4.9 (a)	—	225.7
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale (b)	(59.7)	—	—	(59.7)
Interest Expense (b)	—	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains) Losses	—	—	2.3	2.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(59.7)	1.5	(2.5)	(60.7)
Income Tax (Expense) Benefit	(12.5)	0.3	(0.5)	(12.7)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(47.2)	1.2	(2.0)	(48.0)
Net Current Period Other Comprehensive Income (Loss)	173.6	6.1	(2.0)	177.7
Balance in AOCI as of September 30, 2021	$ 283.9	$ (26.1)	$ 16.9	$ 274.7

	Cash Flow Hedges		Pension	
Three Months Ended September 30, 2020	**Commodity**	**Interest Rate**	**and OPEB**	**Total**
		(in millions)		
Balance in AOCI as of June 30, 2020	$ (81.4)	$ (55.3)	$ (36.2)	$ (172.9)
Change in Fair Value Recognized in AOCI	10.2	1.9 (a)	—	12.1
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (b)	33.3	—	—	33.3
Interest Expense (b)	—	1.3	—	1.3
Amortization of Prior Service Cost (Credit)	—	—	(4.9)	(4.9)
Amortization of Actuarial (Gains) Losses	—	—	2.6	2.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	33.2	1.3	(2.3)	32.2
Income Tax (Expense) Benefit	7.1	0.2	(0.5)	6.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	26.1	1.1	(1.8)	25.4
Net Current Period Other Comprehensive Income (Loss)	36.3	3.0	(1.8)	37.5
Balance in AOCI as of September 30, 2020	$ (45.1)	$ (52.3)	$ (38.0)	$ (135.4)

AEP

Nine Months Ended September 30, 2021	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2020	$ (60.6)	$ (47.5)	$ 23.0	$ (85.1)
Change in Fair Value Recognized in AOCI	534.5	17.6 (a)	—	552.1
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	0.7	—	—	0.7
Purchased Electricity for Resale (b)	(241.2)	—	—	(241.2)
Interest Expense (b)	—	4.8	—	4.8
Amortization of Prior Service Cost (Credit)	—	—	(14.5)	(14.5)
Amortization of Actuarial (Gains) Losses	—	—	6.8	6.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(240.5)	4.8	(7.7)	(243.4)
Income Tax (Expense) Benefit	(50.5)	1.0	(1.6)	(51.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(190.0)	3.8	(6.1)	(192.3)
Net Current Period Other Comprehensive Income (Loss)	344.5	21.4	(6.1)	359.8
Balance in AOCI as of September 30, 2021	$ 283.9	$ (26.1)	$ 16.9	$ 274.7

Nine Months Ended September 30, 2020	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)	$ (32.7)	$ (147.7)
Change in Fair Value Recognized in AOCI	(48.6)	(43.6) (a)	—	(92.2)
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	(0.3)	—	—	(0.3)
Purchased Electricity for Resale (b)	135.7	—	—	135.7
Interest Expense (b)	—	3.6	—	3.6
Amortization of Prior Service Cost (Credit)	—	—	(14.4)	(14.4)
Amortization of Actuarial (Gains) Losses	—	—	7.7	7.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	135.4	3.6	(6.7)	132.3
Income Tax (Expense) Benefit	28.4	0.8	(1.4)	27.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	107.0	2.8	(5.3)	104.5
Net Current Period Other Comprehensive Income (Loss)	58.4	(40.8)	(5.3)	12.3
Balance in AOCI as of September 30, 2020	$ (45.1)	$ (52.3)	$ (38.0)	$ (135.4)

AEP Texas

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ (1.8)	$ (6.5)	$ (8.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2021	$ (1.5)	$ (6.5)	$ (8.0)

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (2.9)	$ (9.3)	$ (12.2)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2020	$ (2.6)	$ (9.3)	$ (11.9)

AEP Texas

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (2.3)	$ (6.6)	$ (8.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	0.1	1.1
Income Tax (Expense) Benefit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	0.1	0.9
Net Current Period Other Comprehensive Income (Loss)	0.8	0.1	0.9
Balance in AOCI as of September 30, 2021	$ (1.5)	$ (6.5)	$ (8.0)

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (3.4)	$ (9.4)	$ (12.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	0.1	1.1
Income Tax (Expense) Benefit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	0.1	0.9
Net Current Period Other Comprehensive Income (Loss)	0.8	0.1	0.9
Balance in AOCI as of September 30, 2020	$ (2.6)	$ (9.3)	$ (11.9)

APCo

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ 8.0	$ 5.9	$ 13.9
Change in Fair Value Recognized in AOCI	0.2	—	0.2
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.6)	—	(0.6)
Amortization of Prior Service Cost (Credit)	—	(1.2)	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.6)	(1.2)	(1.8)
Income Tax (Expense) Benefit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.5)	(1.0)	(1.5)
Net Current Period Other Comprehensive Income (Loss)	(0.3)	(1.0)	(1.3)
Balance in AOCI as of September 30, 2021	$ 7.7	$ 4.9	$ 12.6

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (4.1)	$ 2.2	$ (1.9)
Change in Fair Value Recognized in AOCI	0.7	—	0.7
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.2)	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.2)	(1.2)	(1.4)
Income Tax (Expense) Benefit	(0.1)	(0.3)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.1)	(0.9)	(1.0)
Net Current Period Other Comprehensive Income (Loss)	0.6	(0.9)	(0.3)
Balance in AOCI as of September 30, 2020	$ (3.5)	$ 1.3	$ (2.2)

APCo

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (0.8)	$ 8.0	$ 7.2
Change in Fair Value Recognized in AOCI	9.3	—	9.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(1.0)	—	(1.0)
Amortization of Prior Service Cost (Credit)	—	(3.9)	(3.9)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.0)	(3.9)	(4.9)
Income Tax (Expense) Benefit	(0.2)	(0.8)	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)	(3.1)	(3.9)
Net Current Period Other Comprehensive Income (Loss)	8.5	(3.1)	5.4
Balance in AOCI as of September 30, 2021	$ 7.7	$ 4.9	$ 12.6

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ 0.9	$ 4.1	$ 5.0
Change in Fair Value Recognized in AOCI	(3.8)	—	(3.8)
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.8)	—	(0.8)
Amortization of Prior Service Cost (Credit)	—	(4.0)	(4.0)
Amortization of Actuarial (Gains) Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.8)	(3.6)	(4.4)
Income Tax (Expense) Benefit	(0.2)	(0.8)	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.6)	(2.8)	(3.4)
Net Current Period Other Comprehensive Income (Loss)	(4.4)	(2.8)	(7.2)
Balance in AOCI as of September 30, 2020	$ (3.5)	$ 1.3	$ (2.2)

I&M

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ (7.4)	$ 1.2	$ (6.2)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	—	0.5
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	—	0.4
Net Current Period Other Comprehensive Income (Loss)	0.4	—	0.4
Balance in AOCI as of September 30, 2021	$ (7.0)	$ 1.2	$ (5.8)

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (9.1)	$ (1.7)	$ (10.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.3)	(0.3)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.1)	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.1)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.1)	0.3
Balance in AOCI as of September 30, 2020	$ (8.7)	$ (1.8)	$ (10.5)

I&M

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (8.3)	$ 1.3	$ (7.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.6	—	1.6
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains) Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.6	(0.1)	1.5
Income Tax (Expense) Benefit	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	(0.1)	1.2
Net Current Period Other Comprehensive Income (Loss)	1.3	(0.1)	1.2
Balance in AOCI as of September 30, 2021	$ (7.0)	$ 1.2	$ (5.8)

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (9.9)	$ (1.7)	$ (11.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains) Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.5	(0.1)	1.4
Income Tax (Expense) Benefit	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.2	(0.1)	1.1
Net Current Period Other Comprehensive Income (Loss)	1.2	(0.1)	1.1
Balance in AOCI as of September 30, 2020	$ (8.7)	$ (1.8)	$ (10.5)

PSO

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2021	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of September 30, 2021	$ —

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2020	$ 0.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.3)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
Balance in AOCI as of September 30, 2020	$ 0.3

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2020	$ 0.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0.1)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.1)
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.1)
Net Current Period Other Comprehensive Income (Loss)	(0.1)
Balance in AOCI as of September 30, 2021	$ —

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2019	$ 1.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.0)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.0)
Income Tax (Expense) Benefit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of September 30, 2020	$ 0.3

SWEPCo

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ 0.5	$ 1.4	$ 1.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	(0.5)	(0.1)
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	(0.4)	(0.1)
Net Current Period Other Comprehensive Income (Loss)	0.3	(0.4)	(0.1)
Balance in AOCI as of September 30, 2021	$ 0.8	$ 1.0	$ 1.8

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (1.1)	$ (0.2)	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains) Losses	—	—	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.5)	—
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.4)	—
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.4)	—
Balance in AOCI as of September 30, 2020	$ (0.7)	$ (0.6)	$ (1.3)

SWEPCo

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (0.3)	$ 2.2	$ 1.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.4	—	1.4
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.4	(1.5)	(0.1)
Income Tax (Expense) Benefit	0.3	(0.3)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.1	(1.2)	(0.1)
Net Current Period Other Comprehensive Income (Loss)	1.1	(1.2)	(0.1)
Balance in AOCI as of September 30, 2021	$ 0.8	$ 1.0	$ 1.8

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (1.8)	$ 0.5	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.4	—	1.4
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.4	(1.4)	—
Income Tax (Expense) Benefit	0.3	(0.3)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.1	(1.1)	—
Net Current Period Other Comprehensive Income (Loss)	1.1	(1.1)	—
Balance in AOCI as of September 30, 2020	$ (0.7)	$ (0.6)	$ (1.3)

(a) The change in fair value includes $(1) million and $(1) million, respectively, for the three months ended September 30, 2021 and 2020 and $(5) million and $6 million, respectively, for the nine months ended September 30, 2021 and 2020 related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC.

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

4. RATE MATTERS

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

As discussed in the 2020 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2020 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2021 and updates the 2020 Annual Report.

Coal-Fired Generation Plants (Applies to AEP, PSO and SWEPCo)

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal costs and permits. Management continuously evaluates cost estimates of complying with these regulations which has resulted in, and in the future may result in, a decision to retire coal-fired generating facilities earlier than their currently estimated useful lives.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets are not deemed recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Regulated Generating Units that have been Retired

PSO

The Oklaunion Power Station was retired in September 2020 and sold to a nonaffiliated third-party in October 2020.As of September 30, 2021, PSO has a regulatory asset for accelerated depreciation pending approval recorded on its balance sheet of $33 million. PSO has requested recovery of the Oklaunion Power Station as part of its 2021 Oklahoma base rate case.See “2021 Oklahoma Base Rate Case” section below for additional information.

SWEPCo

In April 2016, Welsh Plant, Unit 2 was retired. As part of the 2016 Texas Base Rate Case, SWEPCo received approval from the PUCT to recover the Texas jurisdictional share of Welsh Plant, Unit 2. See “2016 Texas Base Rate Case” section below for additional information. As part of the 2019 Arkansas Base Rate Case, SWEPCo received approval from the APSC to recover the Arkansas jurisdictional share of Welsh Plant, Unit 2. In December 2020, SWEPCo filed a request with the LPSC to recover the Louisiana jurisdictional share of Welsh Plant, Unit 2. See “2020 Louisiana Base Rate Case” section below for additional information. As of September 30, 2021, SWEPCo has a regulatory asset for plant retirement costs pending approval recorded on its balance sheet of $35 million related to the Louisiana jurisdictional share of Welsh Plant, Unit 2.

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the Federal EPA to close Northeastern Plant, Unit 3, in 2026. The plant was originally scheduled to close in 2040. As a result of the early retirement date, PSO revised the useful life of Northeastern Plant, Unit 3, to the projected retirement date of 2026 and the incremental depreciation is being deferred as a regulatory asset. PSO has requested recovery of Northeastern Plant, Unit 3 as part of its 2021 Oklahoma base rate case. See “2021 Oklahoma Base Rate Case” section below for additional information.

SWEPCo

In January 2020, as part of the 2019 Arkansas Base Rate Case, management announced that the Dolet Hills Power Station was probable of abandonment and was to be retired by December 2026. As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation. In March 2020, management announced plans to retire the plant in 2021.

In November 2020, management announced plans to retire Pirkey Power Plant in 2023 and that it will cease using coal at the Welsh Plant in 2028.As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of September 30, 2021, of generating facilities planned for early retirement:

Plant	Net Book Value	Accelerated Depreciation Regulatory Asset	Cost of Removal Regulatory Liability		Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (a)
			(dollars in millions)				
Northeastern Plant, Unit 3	$ 175.1	$ 123.6	$ 20.0	(b)	2026	(c)	$ 14.9
Dolet Hills Power Station	13.0	126.8	24.4		2021	(d)	7.8
Pirkey Power Plant	135.4	68.0	39.2		2023	(e)	13.5
Welsh Plant, Units 1 and 3	493.7	35.6	58.2	(f)	2028	(g)	33.1

(a) Represents the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(b) Includes Northeastern Plant, Unit 4, which was retired in 2016. Removal of Northeastern Plant, Unit 4, will be performed with Northeastern Plant, Unit 3, after retirement.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Dolet Hills Power Station is currently being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Arkansas and Texas jurisdictions.
(e) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(f) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with Welsh Plant, Units 1 and 3, after retirement.
(g) Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

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

DHLC provides100% of the fuel supply to Dolet Hills Power Station.During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In 2020, management of SWEPCo and CLECO determined DHLC would not proceed developing additional Oxbow Lignite Company (Oxbow) mining areas for future lignite extraction and ceased extraction of lignite at the mine in May 2020.Based on these actions, management revised the estimated useful life of DHLC's and Oxbow's assets to coincide with the date at which extraction was discontinued in the second quarter of 2020 and the date at which delivery of lignite ceased in October 2021. In addition, management also revised the useful life of the Dolet Hills Power Station to 2021 based on the remaining estimated fuel supply available for continued seasonal operation.In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining.

The Dolet Hills Power Station non-fuel costs are recoverable by SWEPCo through base ratesAs of September 30, 2021, SWEPCo's share of the net investment in the Dolet Hills Power Station is $146 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 fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $44 million as of September 30, 2021. Also, as of September 30, 2021, SWEPCo had a net under-recovered fuel balance of $39 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Dolet Hills Power Station. Additional operational, reclamation and other land-related costs incurred by DHLC and Oxbow will be billed to SWEPCo and included in future fuel clauses.

In June 2020, SWEPCo filed a fuel reconciliation with the PUCT for its retail operations in Texas, including Dolet Hills, for the reconciliation period of March 1, 2017 to December 31, 2019. See “2020 Texas Fuel Reconciliation” section below for additional information.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $30 million of additional costs with a recovery period to be determined at a later date.

In March 2021, the APSC approved fuel rates that provide recovery of the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

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

Pirkey Power Plant and Related Fuel Operations (Applies to AEP and SWEPCo)

In 2020, management announced plans to retire the Pirkey Power Plant in 2023.The Pirkey Power Plant non-fuel costs are recoverable by SWEPCo through base rates and fuel costs are recovered through active fuel clauses. As of September 30, 2021, SWEPCo’s share of the net investment in the Pirkey Power Plant is $203 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Power Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo’s fuel inventory and unbilled fuel costs from mining related activities were $108 million as of September 30, 2021. Also, as of September 30, 2021, SWEPCo had a net under-recovered fuel balance of $9 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Pirkey Power Plant.Additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in future fuel clauses.If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition..

2020 Texas Fuel Reconciliation (Applies to AEP and SWEPCo)

In June 2020, SWEPCo filed a fuel reconciliation with the PUCT for its retail operations in Texas for the reconciliation period of March 1, 2017 to December 31, 2019. The fuel reconciliation included total fuel costs of $1.7 billion ($616 million of which is related to the Texas jurisdiction). In January 2021, various parties filed testimony recommending fuel cost disallowances totaling $125 million relating to the Texas jurisdiction. Also in January 2021, SWEPCo filed rebuttal testimony disputing the recommended disallowances.In February 2021, SWEPCo and various parties reached a settlement in principle which resulted in a $10 million reduction in recoverable fuel costs for the reconciliation period, which was recognized in SWEPCo’s 2020 financial statements.In June 2021, the settlement was filed and is currently awaiting approval from the PUCT.If additional costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

__Regulatory Assets Pending Final Regulatory Approval (Applies to all Registrants except AEPTCo)__

Noncurrent Regulatory Assets	AEP September 30, 2021	AEP December 31, 2020
	(in millions)	
<u>Regulatory Assets Currently Earning a Return</u>		
Unrecovered Winter Storm Fuel Costs (a)	$ 1,106.3	$ —
Dolet Hills Power Station Accelerated Depreciation	126.8	71.2
Pirkey Power Plant Accelerated Depreciation	68.0	12.2
Kentucky Deferred Purchase Power Expenses	45.9	41.3
Welsh Plant, Units 1 and 3 Accelerated Depreciation	35.6	3.6
Plant Retirement Costs – Unrecovered Plant, Louisiana	35.2	35.2
Oklaunion Power Station Accelerated Depreciation	33.0	34.4
Dolet Hills Power Station Fuel Costs - Louisiana	20.3	—
Other Regulatory Assets Pending Final Regulatory Approval	25.5	22.8
<u>Regulatory Assets Currently Not Earning a Return</u>		
Storm-Related Costs	325.8	134.2
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
COVID-19	14.0	24.9
Asset Retirement Obligation - Louisiana	10.0	9.1
Other Regulatory Assets Pending Final Regulatory Approval	32.6	27.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 1,904.9	$ 442.2

(a) PSO and SWEPCo have active fuel clauses that allow for the recovery of prudently incurred fuel and purchased power expenses. However, the recovery of these costs from customers may be extended over longer than usual time periods to mitigate the impact on customer bills. See “Impacts of Severe Winter Weather” section below for additional information.

Noncurrent Regulatory Assets	AEP Texas September 30, 2021	AEP Texas December 31, 2020
	(in millions)	
<u>Regulatory Assets Currently Earning a Return</u>		
Advanced Metering System	$ 16.6	$ 16.3
<u>Regulatory Assets Currently Not Earning a Return</u>		
Storm-Related Costs	22.7	0.8
Vegetation Management Program	5.2	3.8
Texas Retail Electric Provider Bad Debt Expense	4.1	—
COVID-19	3.9	10.5
Other Regulatory Assets Pending Final Regulatory Approval	5.3	1.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 57.8	$ 32.9

Noncurrent Regulatory Assets	APCo	
	September 30, 2021	December 31, 2020
	(in millions)	
Regulatory Assets Currently Earning a Return		
COVID-19 – Virginia	$ 6.6	$ 3.7
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	59.8	3.4
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
COVID-19 – West Virginia	0.4	1.5
Environmental Expense Deferral - Virginia	—	9.3
Other Regulatory Assets Pending Final Regulatory Approval	1.2	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 93.9	$ 43.8

Noncurrent Regulatory Assets	I&M	
	September 30, 2021	December 31, 2020
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ —	$ 0.5
Regulatory Assets Currently Not Earning a Return		
COVID-19	1.7	3.8
Other Regulatory Assets Pending Final Regulatory Approval	1.7	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 3.4	$ 4.3

Noncurrent Regulatory Assets	OPCo	
	September 30, 2021	December 31, 2020
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 5.5	$ 4.0
COVID-19	1.9	4.4
Other Regulatory Assets Pending Final Regulatory Approval	0.1	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 7.5	$ 8.4

Noncurrent Regulatory Assets	PSO	
	September 30, 2021	December 31, 2020
	(in millions)	
Regulatory Assets Currently Earning a Return		
Unrecovered Winter Storm Fuel Costs (a)	$ 673.2	$ —
Oklaunion Power Station Accelerated Depreciation	33.0	34.4
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	29.3	15.8
Other Regulatory Assets Pending Final Regulatory Approval	0.9	0.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 736.4	$ 50.5

(a) PSO has an active fuel clause that allows for the recovery of prudently incurred fuel and purchased power expenses. However, the recovery of these costs from customers may be extended over longer than usual time periods to mitigate the impact on customer bills. See "Impacts of Severe Winter Weather" section below for additional information.

Noncurrent Regulatory Assets	SWEPCo September 30, 2021		SWEPCo December 31, 2020	
	(in millions)			
Regulatory Assets Currently Earning a Return				
Unrecovered Winter Storm Fuel Costs (a)	$	433.1	$	—
Dolet Hills Power Station Accelerated Depreciation		126.8		71.2
Pirkey Power Plant Accelerated Depreciation		68.0		12.2
Welsh Plant, Units 1 and 3 Accelerated Depreciation		35.6		3.6
Plant Retirement Costs – Unrecovered Plant, Louisiana		35.2		35.2
Dolet Hills Power Station Fuel Costs- Louisiana		20.3		—
Other Regulatory Assets Pending Final Regulatory Approval		2.3		2.2
Regulatory Assets Currently Not Earning a Return				
Storm-Related Costs		155.4		99.3
Asset Retirement Obligation - Louisiana		10.0		9.1
Other Regulatory Assets Pending Final Regulatory Approval		19.3		14.5
Total Regulatory Assets Pending Final Regulatory Approval	$	906.0	$	247.3

(a) SWEPCo has an active fuel clause that allows for the recovery of prudently incurred fuel and purchased power expenses. However, the recovery of these costs from customers may be extended over longer than usual time periods to mitigate the impact on customer bills. See "Impacts of Severe Winter Weather" section below for additional information.

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

Impacts of Severe Winter Weather

Storm Restoration Costs (Applies to AEP, APCo and SWEPCo)

In February 2021, severe winter weather impacted the service territories of APCo, KPCo and SWEPCo resulting in power outages and extensive damage to transmission and distribution infrastructures. As a result, incremental restoration expenses have been deferred related to the severe winter weather. The storm restoration costs are as follows:

Company	Jurisdiction	September 30, 2021 Capital		O&M		Regulatory Asset		Total	
		(in millions)							
APCo	Virginia	$	8.1	$	2.2	$	6.6	$	16.9
APCo	West Virginia		23.5		—		47.0		70.5
SWEPCo	Louisiana		6.0		—		45.4		51.4
KPCo	Kentucky		29.0		5.0		42.6		76.6
	Total	$	66.6	$	7.2	$	141.6	$	215.4

The amounts in the table above represents costs as of September 30, 2021. In March 2021, the LPSC approved the deferral of incremental other operation and maintenance storm restoration expenses related to the Louisiana jurisdiction for SWEPCo.Similarly, in April 2021, the KPSC approved deferral of KPCo's incremental other operation and maintenance storm restoration expenses. KPCo intends to seek recovery of these incremental storm restoration costs in their next base rate case while APCo is expected to seek recovery in separate filings. In October 2021, SWEPCo requested recovery of these storm costs, in addition to storm costs from Hurricanes Delta and Laura, in a filing with the LPSCAs part of the filing, SWEPCo requested recovery of the carrying charges on the regulatory asset at a weighted average cost of capital through a rider beginning in January 2022. If any of the restoration costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

February 2021 Severe Winter Weather Impacts in SPP (Applies to AEP, PSO and SWEPCo)

The February 2021 severe winter weather also had a significant impact in SPP resulting in the declaration of Energy Emergency Alert Levels 2 and 3 for the first time in SPP's history. The winter storm increased the demand for natural gas and restricted the available natural gas supply resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. From February 9, 2021, to February 20, 2021, PSO's and SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are as follows:

	PSO	SWEPCo		Total
		(in millions)		
Retail Customers (a)	$ 673.2	$ 433.1	(b)	$ 1,106.3
Wholesale Customers	—	55.8		55.8
Total	$ 673.2	$ 488.9		$ 1,162.1

(a) These costs were deferred as regulatory assets as of September 30, 2021.
(b) SWEPCo's balance consists of $107 million, $151 million and $175 million related to the Arkansas, Louisiana and Texas jurisdictions, respectively.

Retail Customers

PSO and SWEPCo have active fuel clauses that allow for the recovery of prudently incurred fuel and purchased power expensesGiven the significance of these costs, PSO and SWEPCo expect the costs to be subject to prudency reviewsManagement believes these costs are probable of future recovery, but expects the recovery period to be extended to mitigate the impact on customer bills.

In March 2021, the APSC issued an order authorizing recovery of the Arkansas jurisdictional share of the retail customer fuel costs over five years, with the appropriate carrying charge to be determined at a later date. Accordingly, in April 2021, SWEPCo began recovery of its Arkansas jurisdictional share of these fuel costs, which are subject to true-up by the APSC.SWEPCo is recovering these fuel costs at an interim carrying charge of 0.8%. Also in April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of6.05% which has been supported by APSC staff. Various other parties have recommended recovery periods ranging from 5-20 years with a carrying charge of 1.65%. The APSC ordered more testimony regarding the option of utilizing securitization to recover the fuel costs.SWEPCo is awaiting a decision from the APSC. The prudency of these fuel costs is expected to be addressed in a separate proceeding.

In March 2021, the LPSC approved a special order granting a temporary modification to the FAC that allows SWEPCo to recover the Louisiana jurisdictional share of these retail fuel costs over a longer period than what the FAC traditionally allows. In April 2021, SWEPCo began recovery of its Louisiana jurisdictional share of these fuel costs based on a five year recovery period. SWEPCo is recovering these fuel costs at an interim carrying charge of 3.25%. SWEPCo will work with the LPSC to finalize the actual recovery period and determine the appropriate carrying charge in future proceedings.

In April 2021, the OCC approved a waiver for PSO allowing the deferral of the extraordinary fuel and purchase of electricity costs, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. Also in April 2021, legislation was enacted in Oklahoma to permit securitization of the extraordinary fuel and purchase of electricity costs impacting the utilities within the state. Under the legislation, the OCC has the authority to determine, after receiving an application from a rate-regulated utility, if the extraordinary fuel and purchase of electricity costs incurred in February 2021 may be mitigated through securitization to reduce the impact on customer bills. PSO has filed an application for a financing order to pursue securitization. The application requests an order on the prudency of the extraordinary fuel and purchase of electricity costs and a carrying charge of the commission authorized weighted average cost of capital until securitization bonds can be issued. In October 2021, OCC staff and intervenors filed testimony supporting securitization of these costs and a carrying charge until costs are securitized ranging from the interim rate of 0.75% to the actual cost of capital used to finance the costs of 2.32%. In addition, OCC staff supported the prudency of PSO's requested costs while one intervenor recommended disallowances of up to $40 million. A procedural schedule has been set with an ALJ report to be filed in January 2022. An order from the OCC is expected in the first quarter of 2022.

In August 2021, SWEPCo filed an application with the PUCT to implement a net interim fuel surcharge for the Texas jurisdictional share of these retail fuel costs. The application supported a five-year recovery at a carrying charge of 7.18%. In October 2021, various intervenors filed testimony supporting a five-year recovery with a carrying charge ranging from 0.082% to 1.625%. A hearing with the PUCT is scheduled for November 2021.

Wholesale Customers

During the first quarter of 2021, SWEPCo billed wholesale customers $104 million resulting from the severe winter weather events. SWEPCo worked with wholesale customers to establish payment terms for the outstanding accounts receivable. As of September 30, 2021, $56 million of accounts receivable from wholesale customers are outstanding. Management believes these receivables are probable of future collection.

PSO and SWEPCo Cash Flow Implications

PSO and SWEPCo evaluated financing alternatives to address the timing difference between the payment of the estimated natural gas expenses and purchases of electricity to suppliers and subsequent recovery from customers. In March 2021, PSO drew $100 million on its revolving credit facility and SWEPCo issued $600 million of Senior Unsecured Notes. In March 2021, Parent entered into a $500 million 364-day Term Loan and borrowed the full amount. The proceeds from this loan were used to help fund capital contributions to PSO and SWEPCo totaling $425 million and $100 million, respectively. In April 2021, PSO received an additional capital contribution from Parent of $125 million to further address these costs.

Although the February 2021 severe winter weather did not materially impact AEP's results of operations for the three and nine months ended September 30, 2021, if either PSO or SWEPCo is unable to recover these fuel and purchased power costs, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

COVID-19 Pandemic

During 2020, AEP's electric operating companies informed both retail customers and state regulators that disconnections for non-payment were temporarily suspended. Shortly thereafter, AEP's state regulators also imposed temporary moratoria on customary disconnection practices. As of September 30, 2021, AEP's electric operating companies have resumed customary disconnection practices in all regulated jurisdictions with the exception of residential customers in Virginia. AEP continues to work with regulators and stakeholders in Virginia and management currently anticipates resuming customary disconnection practices once available relief funds are received from the state. Continuing adverse economic conditions may result in the inability of customers to pay for electric service, which could affect revenue recognition and the collectability of accounts receivable. If any costs related to COVID-19 are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

AEP Texas Interim Transmission and Distribution Rates

Through September 30, 2021, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is approximately $229 million. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition. AEP Texas is required to file for a comprehensive rate review no later than April 5, 2024.

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

2017-2019 Virginia Triennial Review

In November 2020, the Virginia SCC issued an order on APCo's 2017-2019 Triennial Review filing concluding that APCo earned above its authorized ROE but within its ROE band for the 2017-2019 period, resulting in no refund to customers and no change to APCo base rates on a prospective basis. The Virginia SCC approved a prospective9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top).

In December 2020, an intervenor filed a petition at the Virginia SCC requesting reconsideration of: (a) the failure of the Virginia SCC to apply a threshold earnings test to the approved regulatory asset for APCo's closed coal-fired generation assets, (b) the Virginia SCC's use of a 2011 benchmark study to measure the replacement value of capacity for purposes of APCo's 2017 – 2019 earnings test and (c) the reasonableness and prudency of APCo's investments in AMI meters.

In December 2020, APCo filed a petition at the Virginia SCC requesting reconsideration of: (a) certain issues related to APCo's going-forward rates and (b) the Virginia SCC's decision to deny APCo tariff changes that align rates with underlying costs.For APCo's going-forward rates, APCo requested that the Virginia SCC clarify its final order and clarify whether APCo's current rates will allow it to earn a fair return. If the Virginia SCC's order did conclude on APCo's ability to earn a fair return through existing base rates, APCo further requested that the Virginia SCC clarify whether it has the authority to also permit an increase in base rates.

In March 2021, an intervenor filed its assignments of error with the Virginia Supreme Court related to the appeal of the November 2020 order in which it stated the Virginia SCC erred:(a) in determining that Virginia law did not apply to its determination to permit amortization for recovery of costs associated with retired coal-fired generation assets, (b) in establishing a new regulatory asset for a cost incurred outside of the triennial review period due to its failure to apply a threshold earnings test before approving deferred cost recovery and (c) in misapplying the requirement that APCo bear the burden of demonstrating that power purchases made by APCo from its affiliate, OVEC, were priced at the lower of OVEC's cost or the market price for nonaffiliated power.

In March 2021, APCo filed its assignments of error with the Virginia Supreme Court related to its appeal of the November 2020 order in which it stated the Virginia SCC erred: (a) in finding that costs associated with asset impairments related to early retirement determinations made by APCo for certain generation facilities should not be attributed to the test periods under review and deemed fully recovered in the period recorded, (b) in finding that it was permitted to evaluate the reasonableness of APCo's decision to record, per books for financial reporting purposes, asset impairments related to early retirement determinations for certain generation facilities, (c) as a result of the errors described in (a) and (b), in denying APCo an increase in rates, (d) in failing to review and make any findings regarding whether APCo's rates would allow it to earn a fair rate of return going forward, (e) in denying APCo an increase in base rates by failing to ensure that APCo has an opportunity to recover its costs and earn a fair rate of return, thereby resulting in a taking of private property for public use without just compensation and (f) in retroactively adjusting APCo’s depreciation expense for purposes of calculating APCo’s earnings for the 2017-2019 triennial period.

In March 2021, the Virginia SCC issued an order confirming certain of its decisions from the November 2020 order and rejecting the various requests for reconsideration from APCo and an intervenor. In confirming its decision to reject an intervenor’s recommendation that APCo’s AMI costs incurred during the triennial period be disallowed, the Virginia SCC clarified that APCo established the need to replace its existing AMR meters, and that based on the uncertainty surrounding the continued manufacturing and support of AMR technology, APCo reasonably chose to replace them with AMI meters. In March 2021, APCo filed a notice of appeal of the reconsideration order with the Virginia Supreme Court.In September 2021, APCo submitted its brief before the Virginia Supreme Court. The brief was in alignment with the assignments of error filed by APCo in March 2021.In October 2021, the Virginia SCC and certain intervenors filed briefs with the Virginia Supreme Court disagreeing with APCo’s assignments of error in its appeal of the Triennial Review decision. Additionally, the Virginia SCC and APCo filed briefs disagreeing with an intervenor’ s assignments of error in a separate appeal of the same decision.

APCo ultimately seeks an increase in base rates through its appeal to the Virginia Supreme Court.Among other issues, this appeal includes APCo’s request for proper treatment of the closed coal-fired plant assets in APCo’s 2017-2019 triennial period, reducing APCo’s earnings below the bottom of its authorized ROE band.If APCo’s appeals regarding treatment of the closed coal plants are granted by the Virginia Supreme Court, it could initially reduce future net income and impact financial condition. The initial negative impact for the write-off of closed coal-fired plant asset balances would potentially be partially offset by an increase in base rates for earning below APCo’s 2017-2019 authorized ROE band.

CCR/ELG Compliance Plan Filings

In December 2020, APCo submitted filings with the Virginia SCC and WVPSC requesting approvals necessary to implement CCR/ELG complianc plans at the Amos and Mountaineer Plants. Intervenors in Virginia and West Virginia recommended that only the CCR-related investments be constructed at Amos and Mountaineer and, as a consequence, that APCo close these generating facilities at the end of 2028.

In August 2021, the Virginia SCC issued an order approving APCo’s request to construct CCR-related investments at the Amos and Mountaineer Plants and approved recovery of CCR-related other operation and maintenance expenses and investments through an active rider. The order denied APCo’s request to construct the ELG investments and denied recovery of previously incurred ELG costsAPCo may refile for approval of the ELG investments and previously incurred ELG costs at a later date.

Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approve recovery of the West Virginia jurisdictional share of these costs through an active rider. In September 2021, APCo submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021Due to the initial rejection by the Virginia SCC of the Virginia jurisdictional share of the ELG investments, APCo requested the WVPSC consider approving the construction and recovery of all ELG cost at the plants. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed APC to proceed with CCR/ELG compliance plans that would allow the plants to continue operating beyond 2028.The WVPSC’s order further states that APCo will not share capacity and energy from the plants with customers from Virginia if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plants to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that APCo will be given the opportunity to recover, from West Virginia customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plants beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. In October 2021, an intervenor filed a petition for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

APCo expects total Amos and Mountaineer Plant ELG investment, including AFUDC, to be approximately $177 million. As of September 30, 2021, APCo's Virginia jurisdictional share of the net book value, before cost of removal including CWIP and inventory, of the Amos and Mountaineer Plants was approximately $1.5 billion and APCo's Virginia jurisdictional share of its ELG investment balance in CWIP for these plants was $19 million.

If any of the ELG costs are not approved for recovery and/or the retirement dates of the Amos and Mountaineer plants are accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through September 30, 2021, AEP's share of ETT's cumulative revenues that are subject to review is approximately $1.3 billion. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. ETT is required to file for a comprehensive rate review no later than February 1, 2023, during which the $1.3 billion of cumulative revenues above will be subject to review.

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

Indiana Earnings Test Filings

I&M is required by Indiana law to submit an earnings test evaluation for the most recent one-year and five-year periods as part of I&M's semi-annual Indiana FAC filings. These earnings test evaluations require I&M to include a credit in the FAC factor computation for periods in which I&M earned above its authorized return for both the one-year and five-year periods. The credit is determined as 50% of the lower of the one-year or five-year earnings above the authorized level. In July 2021, I&M submitted its FAC filing and earnings test evaluation for the period ended May 2021, which calculated a credit due to customers of $9 million. In September 2021, the IURC approved the FAC filing and earnings test evaluation, with the credit to customers starting in October 2021 through the FAC.

2021 Indiana Base Rate Case

In July 2021, I&M filed a request with the IURC for a $104 million annual increase in Indiana base rates based upon a proposed 10% ROE. I&M proposed a phased-in annual increase in rates of $73 million effective in May 2022 with the remaining $31 million annual increase in rates to be effective January 2023. The proposed annual increase includes $7 million related to an annual increase in depreciation expense, driven by increased depreciation rates and proposed investments. The request also includes a new AMI rider for proposed meter projects.

In October 2021, intervenors submitted testimony recommending an annual decrease in Indiana base rates ranging from $13 million to $68 million based upon a ROE ranging from 9.1% to 9.3%. Among other issues, intervening parties recommended that the IURC reject the following: (a) I&M's proposed re-allocation of capacity costs related to the 2020 loss of a significant FERC wholesale contract, (b) continued recovery of a return on remaining Rockport Unit 2 leasehold improvements once the related lease ends in December 2022, (c) inclusion of net operating loss in rate base, (d) the proposed new AMI rider and (e) inclusion of prepaid pension and OPEB assets in rate base. I&M rebuttal testimony is due in November 2021. If any costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

<u>KPCo Rate Matters</u> (Applies to AEP)

CCR/ELG Compliance Plan Filings

KPCo and WPCo each own a 50% interest in the Mitchell Plant. In December 2020 and February 2021, WPCo and KPCo filed requests with the WVPSC and KPSC, respectively, to obtain the regulatory approvals necessary to implement CCR and ELG compliance plans and seek recovery of the estimated $132 million investment for the Mitchell Plant that would allow the plant to continue operating beyond 2028. Within those requests, WPCo and KPCo also filed a $25 million alternative to implement only the CCR-related investments with the WVPSC and KPSC, respectively, which would allow the Mitchell Plant to continue operating only through 2028.

In July 2021, the KPSC issued an order approving the CCR only alternative and rejecting the full CCR and ELG compliance plan. In August 2021, the WVPSC approved the full CCR and ELG compliance plan for the WPCo share of the Mitchell Plant. In September 2021, WPCo submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021. Due to the rejection by the KPSC of the KPCo share of the ELG investments, WPCo requested the WVPSC consider approving the construction and recovery of all ELG costs at the plant. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed WPCo to proceed with CCR/ELG compliance plans that would allow the plant to continue operating beyond 2028. The WVPSC's order further states WPCo will not share capacity and energy from the plant with KPCo customers if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plant to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that WPCo will be given the opportunity to recover, from its customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plant beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. In October 2021, an intervenor filed a petition for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

As of September 30, 2021, KPCo's share of the Mitchell Plant's ELG investment balance in CWIP was $2 million. As of September 30, 2021, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $587 million.

If any of the ELG costs are not approved for recovery and/or the retirement date of the Mitchell Plant is accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

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

2020 Ohio Base Rate Case

In June 2020, OPCo filed a request with the PUCO for a $42 million annual increase in base rates based upon a proposed 10.15% ROE net of existing riders.

In November 2020, the PUCO staff filed testimony supporting an annual revenue decrease ranging from $102 million to $123 million based upon a ROE of 8.76% to 9.78%. The difference between OPCo's request and the staff testimony are primarily due to reductions in: (a) demand-side management programs of $40 million, (b) ROE ranging from $9 million to $30 million, (c) employee-related expenses of $23 million, (d) rate base of $19 million, (e) property taxes of $17 million, (f) other various expenses of $15 million, (g) depreciation expense of $11 million and (h) vegetation management programs of $10 million which is subject to over/under-recovery through a rider. The staff's proposed disallowance of plant in service could also result in a write-off of up to $27 million. In addition, the staff recommended that capitalized incentives be excluded from base rates prospectively and also recommended annual revenue caps for the DIR of $57 million in 2021, $78 million in 2022, $96 million in 2023 and $46 million for the first five months of 2024. In December 2020, OPCo and intervenors filed objections.

In March 2021, OPCo, the PUCO staff and various intervenors filed a joint stipulation and settlement agreement with the PUCO. The agreement includes a $68 million annual decrease in base rates based on an ROE of 9.7%. The difference between OPCo's requested annual base rate increase and the agreed upon decrease is primarily due to a reduction in the requested ROE, the removal of proposed future energy efficiency costs and a decrease in vegetation management expenses moved to recovery in riders. Additionally, the agreement includes: (a) an increased fixed monthly residential customer charge, (b) the discontinuation of rate decoupling and (c) the continuation of the DIR with annual revenue caps of $57 million in 2021, $91 million in 2022, $116 million in 2023 and $51 million for the first five months of 2024. Annual revenue caps for the DIR can be increased if OPCo achieves certain reliability standards. If the joint stipulation and settlement agreement is approved by the PUCO, new base rates will go into effect 14 days after such approval. A hearing took place with the PUCO in May 2021 and initial briefs were filed in June 2021 followed by reply briefs in July 2021. An order from the PUCO is expected in the fourth quarter of 2021. If the joint stipulation and settlement agreement is denied by the PUCO, it could reduce future net income and cash flows and impact financial condition.

2019 Ohio DIR Audit

OPCo conducts business under an ESP as approved by the PUCO which subjects the DIR to annual audits. In August 2020, a third-party consulting company filed an audit report with the PUCO indicating that OPCo exceeded its 2019 authorized revenue limit by $7 million. In September 2021, the third-party consulting company adjusted its findings in the previous audit, indicating that OPCo exceeded its 2019 authorized revenue limit by $3 million. Management disagrees with the audit results and believes that OPCo was below its authorized revenue limit in 2019. If the results of the audit are upheld by the PUCO and any refunds to customers or revenue reductions are ordered, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

2021 Oklahoma Base Rate Case

In April 2021, PSO filed a request with the OCC for a $72 million net annual increase in Oklahoma base rates based upon a 10% ROE. The proposed net annual increase includes: (a) a $57 million annual depreciation expense increase, of which $45 million is related to the accelerated depreciation recovery of the Oklaunion Power Station and Northeastern Plant, Unit 3 through 2026 and (b) $11 million related to increased SPP expenses. PSO also requested the continuation of its SPP Transmission Tariff that tracks transmission costs as well as continuation and expansion of its Distribution and Safety Reliability Rider to recover projects in its proposed grid transformation and revitalization plan, which includes $100 million annual capital spend over a 5 year period. In August 2021, PSO updated its request for a net annual revenue increase to appropriately reflect certain cost reductions and annualized rider revenues transitioning into base rates. PSO's updated request filed with the OCC is for a $128 million net annual increase in Oklahoma base rates based upon a 10% ROE.

Also, in August 2021, OCC staff and various intervenors filed testimony supporting net annual revenue changes ranging from a $44 million net decrease to a $74 million net increase based upon a ROE of 9.0% to 9.4%. The difference between PSO's request and OCC staff and intervenor testimony is primarily due to: (a) disallowance of recovery of Oklaunion Power Station or allowing recovery with a debt-only return over Oklaunion Power Station's original useful life of 2046, (b) rejection of PSO's request to accelerate the recovery of Northeastern Plant, Unit 3 from its original retirement date of 2040 to its projected retirement date of 2026, (c) disallowance of $41 million in SPP transmission expense and denial of prospective tracking of most SPP transmission costs through the SPP transmission tariff, (d) opposition to PSO's recommendation to include its deferred tax asset associated with net operating loss on a stand-alone tax basis in rate base, (e) a lower recommended ROE and (f) recommendations to discontinue the Distribution and Safety Reliability Rider.

In September 2021, PSO, OCC staff and certain intervenors filed a contested joint stipulation and settlement agreement with the OCC that included a net annual revenue increase of $51 million based upon a 9.4% ROE. The agreement also included: (a) recovery of, with a debt return on, the Oklaunion Power Station regulatory asset through 2046 and continued recovery of Northeastern Plant, Unit 3 through 2040, (b) updated depreciation rates for plant in service, not including coal production plant, (c) approval to defer a weighted average cost of capital carrying charge on PSO's deferred tax asset associated with net operating loss on a stand-alone tax basis beginning in November 2021 and, contingent upon receipt of a supportive private letter ruling from the IRS, approval to collect the deferral through a rider over a 20-month period, (d) modification of the SPP transmission tariff to reduce the scope of tracked transmission expense and (e) modification of the Distribution Reliability and Safety Rider to limit recovery to previously approved projects not in service as of June 2021. In October 2021, a hearing on the merits of the contested joint stipulation and settlement agreement was held at the OCC. PSO will implement interim rates subject to refund starting with the November 2021 billing cycle. An order is expected in December 2021. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

2012 Texas Base Rate Case

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

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant. In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. No parties filed a motion for rehearing with the Texas Supreme Court. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgement affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. SWEPCo disagrees with the Court of Appeals decision and expects to submit a Petition for Review with the Texas Supreme Court in November 2021.

If SWEPCo is ultimately unable to recover capitalized Turk Plant costs including AFUDC in excess of the Texas jurisdictional capital cost cap it would result in a pretax net disallowance ranging from $80 million to $100 million. In addition, if AFUDC is ultimately determined to be included in the Texas jurisdictional capital cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $160 million related to revenues collected from February 2013 through September 2021 and such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis.

2016 Texas Base Rate Case

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

As a result of the final order in 2017, SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors. The appeal will move forward following the conclusion of the 2012 Texas Base Rate Case. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

Hurricane Laura

In August 2020, Hurricane Laura hit the coasts of Louisiana and Texas, causing power outages to more than 130,000 customers across SWEPCo's service territories. Prior to Hurricane Laura, SWEPCo did not have a catastrophe reserve or automatic deferral authority within any of its jurisdictions. In October 2020, the LPSC issued an order allowing Louisiana utilities, including SWEPCo, to establish a regulatory asset to track and defer expenses associated with Hurricane Laura. In October 2020, as part of the 2020 Texas Base Rate Case, SWEPCo requested deferral authority of incremental other operation and maintenance expenses. As of September 30, 2021, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $92 million ($89 million of which has been deferred as a regulatory asset related to the Louisiana jurisdiction) and incremental capital expenditures of $18 million, all of which is related to the Louisiana jurisdiction. In October 2021, SWEPCo requested recovery of these storm costs, in addition to Hurricane Delta and February 2021 winter storm costs, in a filing with the LPSC. See "Storm Restoration Costs" above for more information. If any costs related to Hurricane Laura are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Hurricane Delta

In October 2020, Hurricane Delta hit the coast of Louisiana, causing power outages to more than 23,000 customers in SWEPCo's Louisiana jurisdiction. In November 2020, the LPSC issued an order allowing Louisiana utilities, including SWEPCo, to establish a regulatory asset to track and defer expenses associated with Hurricane Delta. As of September 30, 2021, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $18 million, which has been deferred as a regulatory asset. Also, management estimates that SWEPCo has incurred incremental capital expenditures of $2 million. In October 2021, SWEPCo requested recovery of these storm costs, in addition to Hurricane Laura and February 2021 winter storm costs, in a filing with the LPSC. See "Storm Restoration Costs" above for more information. If any costs related to Hurricane Delta are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2020 Texas Base Rate Case

In October 2020, SWEPCo filed a request with the PUCT for a $105 million annual increase in Texas base rates based upon a proposed 10.35% ROE. The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $90 million primarily due to increased investments. The proposed net annual increase: (a) includes $5 million related to vegetation management to maintain and improve the reliability of SWEPCo's Texas jurisdictional distribution system, (b) requests a $10 million annual depreciation increase and (c) seeks $2 million annually to establish a storm catastrophe reserve. In addition, SWEPCo requested recovery of the Texas jurisdictional share of the Dolet Hills Power Station of $45 million which is expected to be retired by the end of 2021. SWEPCo subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to $100 million which would result in an $85 million net annual base rate increase after moving the proposed riders to rate base.

In August 2021, an ALJ issued a Proposal for Decision (PFD) which would provide SWEPCo with an annual revenue increase of $43 million based upon a 9.45% ROE. The PFD also includes: (a) rates implemented retroactively back to March 18, 2021, (b) $5 million of the proposed increase related to vegetation management, (c) a denial of the requested $2 million annually to establish a storm catastrophe reserve and (d) the creation of a rider that would recover the Dolet Hills Power Station as if it were in rate base until its retirement at the end of 2021 and starting in 2022 the remaining net book value would be recovered as a regulatory asset through 2046. An order from the PUCT is expected in the fourth quarter of 2021. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2020 Louisiana Base Rate Case

In December 2020, SWEPCo filed a request with the LPSC for a $134 million annual increase in Louisiana base rates based upon a proposed 10.35% ROE. In March 2021, SWEPCo filed a revised request with the LPSC to remove hurricane storm costs from the base rate case filing and seek recovery of those costs in a separate filing. SWEPCo's revised filing requested an annual increase in Louisiana base rates of $114 million. The request would extend the formula rate plan for five years and includes modifications to the formula rate plan to allow for forward-looking transmission costs, reflects the impact of net operating losses associated with the acceleration of certain tax benefits and incorporates future federal corporate income tax changes. The proposed net annual increase requests a $32 million annual depreciation increase to recover Louisiana's share of the Dolet Hills Power Station, Pirkey Power Plant and Welsh Plant, all of which are expected to be retired early. In April 2021, the LPSC approved SWEPCo's request to remove the hurricane storm costs from the base rate case filing. In October 2021, SWEPCo requested recovery of the $152 million of storm costs associated with Hurricanes Delta, Laura and the February 2021 winter storm in a filing with the LPSC. See "Storm Restoration Costs" above for more information.

In July 2021, the LPSC staff filed testimony supporting a $6 million annual increase in base rates based upon an ROE of 9.1% while other intervenors recommended an ROE ranging from 9.35% to 9.8%. The primary differences between SWEPCo's requested annual increase in base rates and the LPSC staff's recommendation include: (a) a reduction in depreciation expense, (b) recovery of Dolet Hills Power Station and Pirkey Power Plant in a separate rider mechanism, (c) the rejection of SWEPCo's proposed adjustment to include a stand-alone net operating loss carryforward deferred tax asset in rate base and (d) a reduction in the proposed ROE.

In September 2021, SWEPCo filed rebuttal testimony supporting a revised requested annual increase in base rates of $95 million. The primary differences in the rebuttal testimony from the previous revised request of $114 million are modifications to the proposed recovery of the Dolet Hills Power Station and revisions to various proposed amortizations. LPSC staff and intervenor responses to SWEPCo's rebuttal testimony were filed in October 2021.

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

2021 Arkansas Base Rate Case

In July 2021, SWEPCo filed a request with the APSC for an $85 million annual increase in Arkansas base rates based upon a proposed 10.35% ROE. The proposed annual increase includes: (a) a $41 million revenue requirement for the North Central Wind Facilities, (b) a $14 million annual depreciation increase primarily due to recovery of the Dolet Hills Power Station through 2026 and Pirkey Plant and Welsh Plant, Units 1 and 3 through 2037 and (c) a $6 million increase due to SPP costs. SWEPCo requests that rates are effective beginning in June 2022.Staff and intervenor testimony is expected in December 2021.

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

FERC Rate Matters

FERC SPP Transmission Formula Rate Challenge (Applies to AEP, AEPTCo, PSO and SWEPCo)

In May 2021, certain joint customers submitted a formal challenge at the FERC related to the 2020 Annual Update of the 2019 SPP Transmission Formula Rates of the AEP transmission owning subsidiaries within SPP.Management has reviewed the formal challenge and responses were filed with the FERC at the end of July 2021.If the FERC orders revenue refunds or reductions, it could reduce future net income and cash flows and impact financial condition.

Independence Energy Connection Project (Applies to AEP)

In 2016, PJM approved the Independence Energy Connection Project (IEC) and included it in its Regional Transmission Expansion Plan to alleviate congestion. Transource Energy owns the IEC, which is located in Maryland and Pennsylvania. In June 2020, the Maryland Public Service Commission approved a Certificate of Public Convenience and Necessity to construct the portion of the IEC in MarylandIn May 2021, the Pennsylvania Public Utility Commission (PA PUC) denied the IEC certificate for siting and construction of the portion in PennsylvaniaTransource Energy has appealed the PA PUC ruling in Pennsylvania state court and challenged the ruling before the United States District Court for the Middle District of Pennsylvania. The case before the state court is pending and the case before the United States District Court for the Middle District of Pennsylvania is on hold, pending the outcome of the case in the Pennsylvania state court.

In September 2021, PJM notified Transource Energy that the IEC was suspended to allow for the regulatory and related appeals process to proceed in an orderly manner without breaching milestone dates in the project agreement. PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. PJM will reevaluate the need for the IEC at the end of 2021 during its annual reevaluation process.As of September 30, 2021, AEP's share of IEC capital expenditures was approximately $79 million. The FERC has previously granted abandonment benefits for this project, allowing the full recovery of prudently incurred costs if the project is cancelled for reasons outside the control of Transource Energy. If any of the IEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2020 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP and AEP Texas)

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

AEP has $4 billion and $1 billion revolving credit facilities due in March 2026 and 2023, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of September 30, 2021, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under five uncommitted facilities totaling $375 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2021 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 179.5	October 2021 to August 2022
AEP Texas	2.2	July 2022

Guarantees of Equity Method Investees (Applies to AEP)

In 2019, AEP acquired Sempra Renewables LLC. The transaction resulted in the acquisition of a 50% ownership interest in five non-consolidated joint ventures and the acquisition of two tax equity partnerships. Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of September 30, 2021, the maximum potential amount of future payments associated with these guarantees was $148 million, with the last guarantee expiring in December 2037. The non-contingent liability recorded associated with these guarantees was $29 million, with an additional $2 million expected credit loss liability for the contingent portion of the guarantees. Management considered historical losses, economic conditions and reasonable and supportable forecasts in the calculation of the expected credit loss. As the joint ventures generate cash flows through PPAs, the measurement of the contingent portion of the guarantee liability is based upon assessments of the credit quality and default probabilities of the respective PPA counterparties.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2021, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of September 30, 2021, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss
	(in millions)
AEP	$ 47.8
AEP Texas	11.1
APCo	6.2
I&M	4.1
OPCo	7.6
PSO	4.7
SWEPCo	5.2

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The Owner Trustee owns the Plant and leases equal portions to AEGCo and I&M. The lease is accounted for as an operating lease. The lease terr is for 33 years and at the end of the lease term, AEGCo and I&M have the option to renew the lease at a rate that approximates fair value. In November 2020, management announced that AEP will not renew the lease when it expires in 2022. AEP, AEGCo and I&M have no ownership interest in the Owner

Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of September 30, 2021 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2021	$ 74.0	$ 37.0
2022	147.6	73.8
Total Future Minimum Lease Payments	$ 221.6	$ 110.8

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

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party.Certain boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the respective lessors, ensuring future payments under such leases with maturities up to 2027. As of September 30, 2021, the maximum potential amount of future payments required under the guaranteed leases was $43 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor's rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of September 30, 2021, AEP's boat and barge lease guarantee liability was $2 million, of which $1 million was recorded in Other Current Liabilities and $1 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheets.

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

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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

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

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

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

OPERATIONAL CONTINGENCIES

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

In 2013, the Wilmington Trust Company filed suit 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 sought a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs.

After the litigation proceeded at the District Court and Circuit Court levels, on April 20, 2021, I&M and AEGCo reached an agreement to acquire 100% of the interests in Rockport Plant, Unit 2 for $115.5 million from certain financial institutions that own the unit through trusts established by Wilmington Trust, the nonaffiliated owner trustee of the ownership interests in the unit, with closing to occur as of the end of the Rockport Plant, Unit 2 lease in December 2022. The agreement is subject to customary closing conditions, including regulatory approvals and as of the closing will result in a final settlement of, and release of claims in, the lease litigation. As a result, in May 2021, at the parties’ request, the district court entered a stipulation and order dismissing the case without prejudice to plaintiffs asserting their claims in a re-filed action or a new action. Management believes its financial statements appropriately reflect the resolution of the litigation.

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 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. The denial of those claims was appealed to the AEP System Retirement Plan Appeal Committee and the Committee upheld the denial of claims. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Litigation Related to Ohio House Bill 6 (HB 6)

In 2019, Ohio adopted and implemented HB 6 which benefits OPCo by authorizing rate recovery for certain costs including renewable energy contracts and OVEC's coal-fired generating units. OPCo engaged in lobbying efforts and provided testimony during the legislative process in connection with HB 6. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of an Ohio legislator and associates in connection with an alleged racketeering conspiracy involving the adoption of HB 6. After AEP learned of the criminal allegations against the Ohio legislator and others relating to HB 6, the Company, with assistance from outside advisors, conducted a review of the circumstances surrounding the passage of the bill. We do not believe that AEP was involved in any wrongful conduct in connection with the passage of HB 6.

In August 2020, an AEP shareholder filed a putative class action lawsuit in the United States District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. The amended complaint alleges misrepresentations or omissions by AEP regarding: (a) its alleged participation in or connection to public corruption with respect to the passage of HB 6 and (b) its regulatory, legislative, political contribution, 501(c)(4) organization contribution and lobbying activities in Ohio. The complaint seeks monetary damages, among other forms of relief. On May 10, 2021, the defendants filed a motion to dismiss the securities litigation for failure to state a claim and the motion was fully briefed as of July 26, 2021. The Court has scheduled oral argument for November 23, 2021 on the motion to dismiss. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In January 2021, an AEP shareholder filed a derivative action in the United States District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The first three derivative actions have been stayed pending the resolution of the motion to dismiss the securities litigation. The fourth has been stayed until such time as the court determines to lift the stay. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

On March 1, 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter is directed to the Board of Directors of AEP and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by directors and officers, and that, following such investigation, the Company commence a civil action for breaches of fiduciary duty and related claims and take appropriate disciplinary action against those individuals who allegedly harmed the company. The shareholder that sent the letter has agreed that AEP and the AEP Board may defer consideration of the litigation demand until the resolution of the motion to dismiss the securities litigation. The AEP Board will act in response to the letter as appropriate. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In May 2021, AEP received a subpoena from the SEC's Division of Enforcement seeking various documents, including documents relating to the benefits to AEP from the passage of HB 6 and documents relating to AEP's financial processes and controls.AEP is cooperating fully with the SEC's subpoena. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this inquiry will have a material impact on our financial condition, results of operations, or cash flows.

6. ACQUISITIONS AND DISPOSITIONS

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

ACQUISITIONS

Dry Lake Solar Project (Generation & Marketing Segment)

In November 2020, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% interest in the 100 MW Dry Lake Solar Project (Dry Lake) located in southern Nevada for approximately $114 million. In March 2021, AEP closed the transaction and the solar project was placed in-service in May 2021. Approximately $103 million of the purchase price was paid upon closing of the transaction and the remaining $11 million was paid when the project was placed in-service. In accordance with the accounting guidance for "Business Combinations," management determined that the acquisition of Dry Lake represents an asset acquisition. Additionally, and in accordance with the accounting guidance for "Consolidation," management concluded that Dry Lake is a VIE and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact Dry Lake's economic performance. As the primary beneficiary of Dry Lake, AEP consolidates Dry Lake into its financial statements. As a result, to account for the initial consolidation of Dry Lake, management applied the acquisition method by allocating the purchase price based on the relative fair value of the assets acquired and noncontrolling interest assumed. The fair value of the primary assets acquired and the noncontrolling interest assumed was determined using the market approach. The key input assumptions were the transaction price paid for AEP's interest in Dry Lake and recent third-party market transactions for similar solar generation facilities. The nonaffiliated interest in Dry Lake is presented in Noncontrolling Interests on the balance sheets. Subsequent to close of the transaction, the noncontrolling interest made additional asset contributions of $16 million. As of September 30, 2021, AEP recognized approximately $146 million of Property, Plant and Equipment and approximately $35 million of Noncontrolling Interest on the balance sheets.

North Central Wind Energy Facilities (Vertically Integrated Utilities Segment) (Applies to AEP, PSO and SWEPCo)

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,485 MWs, on a fixed cost turn-key basis at completion. PSO and SWEPCo will own undivided interests of 45.5% and 54.5% of the NCWF, respectively. In total, the three wind facilities will cost approximately $2 billion and consist of Traverse (999 MW), Maverick (287 MW) and Sundance (199 MW). Output from the NCWF will serve retail load in PSO's Oklahoma service territory and both retail and FERC wholesale load in SWEPCo's service territories in Arkansas and Louisiana. The Oklahoma and Louisiana portions of the NCWF revenue requirement, net of PTC benefit, are recoverable through authorized riders beginning at commercial operation and until such time as amounts are reflected in base rates. Recovery of the Arkansas portion of the NCWF revenue requirement is requested in SWEPCo's pending 2021 Arkansas Base Rate Case. The NCWF are subject to various regulatory performance requirements. If these performance requirements are not met, PSO and SWEPCo would recognize a regulatory liability to refund retail customers.

In April 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Sundance during its development and construction for $270 million, the first of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Sundance assets in proportion to their undivided ownership interests. Sundance was placed in-service in April 2021.

In September 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Maverick during its development and construction for $383 million, the second of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Maverick assets in proportion to their undivided ownership interests. Maverick was placed in-service in September 2021.

In accordance with the guidance for “Business Combinations,” management determined that the acquisitions of Sundance and Maverick represent asset acquisitions. As of September 30, 2021, PSO and SWEPCo had approximately $314 million and $376 million, of Property, Plant and Equipment on the balance sheets, respectively, related to the Sundance and Maverick NCWF projects.On an ongoing basis, management further determined that PSO and SWEPCo should apply the joint plant accounting model to account for their respective undivided interests in the assets, liabilities, revenues and expenses of Sundance and Maverick.

The Purchase and Sale Agreement (PSA) includes collective interests in numerous land contracts, as originally executed between the nonaffiliated party and the respective owners of the properties as defined in the contracts. These contracts provide for easement and access rights to the land that Sundance and Maverick were built upon. These interests as lessee in each of the land contracts were transferred to Sundance and Maverick (and subsequently to PSO and SWEPCo) as a part of the closing of the PSA.As of September 30, 2021, the Noncurrent Obligations Under Operating Leases for Sundance are $13 million and $15 million on the balance sheets for PSO and SWEPCo, respectively, and the Noncurrent Obligations Under Operating Leases for Maverick are $18 million and $22 million on the balance sheets for PSO and SWEPCo, respectively.

Desert Sky Wind Farm and Trent Wind Farm (Generation & Marketing Segment)

In August 2020, AEP exercised its call right which required the nonaffiliated member of Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively the LLCs) to sell its noncontrolling interest to AEP. The exercise price for the call right was determined using a discounted cash flow model with agreed input assumptions as well as updates to certain assumptions reasonably expected based on the actual results of the LLCs. As a result, the LLCs are wholly-owned by AEP and management has concluded that the LLCs are no longer VIEs. AEP paid $57 million in cash, derecognized $63 million of Redeemable Noncontrolling Interest within Mezzanine Equity and recorded an increase of $5 million of Paid-In Capital on the balance sheets.

DISPOSITIONS

Conesville Plant (Generation & Marketing Segment)

In June 2020, AEP and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated third-party related to the merchant Conesville Plant site. The purchaser took ownership of the assets and assumed responsibility for environmental liabilities, including ash pond closure, asbestos abatement and decommissioning and demolition of the Conesville Plant site. In consideration of the transfer of the acquired assets to the purchaser and the purchaser’s assumption of liabilities, AEP will pay a total of approximately $98 million over three years, derecognized $106 million in ARO and recorded an immaterial gain on the transaction which is recorded in Other Operation on the statements of income. AEP paid approximately $26 million at closing in June 2020 and made additional payments totaling $38 million in quarterly installments from October 2020 to July 2021. AEP will make additional payments totaling $34 million in quarterly installments from October 2021 to July 2022.

7. BENEFIT PLANS

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

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

Components of Net Periodic Benefit Cost

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

AEP

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 32.3	$ 28.0	$ 2.4	$ 2.5
Interest Cost	34.3	42.0	7.7	10.0
Expected Return on Plan Assets	(57.4)	(66.3)	(22.8)	(23.9)
Amortization of Prior Service Credit	—	—	(17.8)	(17.4)
Amortization of Net Actuarial Loss	25.3	23.5	—	1.4
Net Periodic Benefit Cost (Credit)	$ 34.5	$ 27.2	$ (30.5)	$ (27.4)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 96.9	$ 84.0	$ 7.2	$ 7.5
Interest Cost	102.9	125.9	22.9	29.9
Expected Return on Plan Assets	(172.3)	(198.7)	(68.4)	(71.8)
Amortization of Prior Service Credit	—	—	(53.2)	(52.3)
Amortization of Net Actuarial Loss	76.1	70.3	—	4.4
Net Periodic Benefit Cost (Credit)	$ 103.6	$ 81.5	$ (91.5)	$ (82.3)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 3.0	$ 2.6	$ 0.2	$ 0.2
Interest Cost	2.8	3.5	0.6	0.8
Expected Return on Plan Assets	(4.9)	(5.7)	(1.9)	(2.0)
Amortization of Prior Service Credit	—	—	(1.5)	(1.4)
Amortization of Net Actuarial Loss	2.1	1.9	—	0.1
Net Periodic Benefit Cost (Credit)	$ 3.0	$ 2.3	$ (2.6)	$ (2.3)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 8.9	$ 7.6	$ 0.5	$ 0.6
Interest Cost	8.4	10.5	1.8	2.4
Expected Return on Plan Assets	(14.6)	(17.1)	(5.6)	(6.0)
Amortization of Prior Service Credit	—	—	(4.5)	(4.4)
Amortization of Net Actuarial Loss	6.2	5.8	—	0.4
Net Periodic Benefit Cost (Credit)	$ 8.9	$ 6.8	$ (7.8)	$ (7.0)

APCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 3.0	$ 2.7	$ 0.3	$ 0.3
Interest Cost	4.1	5.0	1.3	1.6
Expected Return on Plan Assets	(7.3)	(8.4)	(3.4)	(3.6)
Amortization of Prior Service Credit	—	—	(2.6)	(2.5)
Amortization of Net Actuarial Loss	3.0	2.8	—	0.2
Net Periodic Benefit Cost (Credit)	$ 2.8	$ 2.1	$ (4.4)	$ (4.0)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 8.9	$ 7.9	$ 0.8	$ 0.8
Interest Cost	12.3	15.2	3.7	4.9
Expected Return on Plan Assets	(21.8)	(25.2)	(10.1)	(10.9)
Amortization of Prior Service Credit	—	—	(7.8)	(7.6)
Amortization of Net Actuarial Loss	9.0	8.4	—	0.7
Net Periodic Benefit Cost (Credit)	$ 8.4	$ 6.3	$ (13.4)	$ (12.1)

I&M

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 4.4	$ 3.9	$ 0.4	$ 0.4
Interest Cost	4.0	4.9	0.8	1.2
Expected Return on Plan Assets	(7.2)	(8.3)	(2.7)	(3.0)
Amortization of Prior Service Credit	—	—	(2.5)	(2.3)
Amortization of Net Actuarial Loss	2.9	2.7	—	0.1
Net Periodic Benefit Cost (Credit)	$ 4.1	$ 3.2	$ (4.0)	$ (3.6)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 13.1	$ 11.6	$ 1.0	$ 1.1
Interest Cost	12.1	14.7	2.6	3.5
Expected Return on Plan Assets	(21.6)	(24.9)	(8.3)	(8.8)
Amortization of Prior Service Credit	—	—	(7.3)	(7.1)
Amortization of Net Actuarial Loss	8.8	8.1	—	0.5
Net Periodic Benefit Cost (Credit)	$ 12.4	$ 9.5	$ (12.0)	$ (10.8)

OPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 2.9	$ 2.4	$ 0.2	$ 0.2
Interest Cost	3.1	3.9	0.7	1.0
Expected Return on Plan Assets	(5.7)	(6.6)	(2.4)	(2.6)
Amortization of Prior Service Credit	—	—	(1.7)	(1.8)
Amortization of Net Actuarial Loss	2.3	2.1	—	0.2
Net Periodic Benefit Cost (Credit)	$ 2.6	$ 1.8	$ (3.2)	$ (3.0)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 8.6	$ 7.2	$ 0.6	$ 0.7
Interest Cost	9.3	11.6	2.3	3.1
Expected Return on Plan Assets	(16.8)	(19.7)	(7.3)	(7.9)
Amortization of Prior Service Credit	—	—	(5.3)	(5.3)
Amortization of Net Actuarial Loss	6.8	6.4	—	0.5
Net Periodic Benefit Cost (Credit)	$ 7.9	$ 5.5	$ (9.7)	$ (8.9)

PSO

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 2.0	$ 1.9	$ 0.1	$ 0.1
Interest Cost	1.7	2.1	0.4	0.6
Expected Return on Plan Assets	(3.0)	(3.6)	(1.3)	(1.3)
Amortization of Prior Service Credit	—	—	(1.1)	(1.0)
Amortization of Net Actuarial Loss	1.2	1.1	—	—
Net Periodic Benefit Cost (Credit)	$ 1.9	$ 1.5	$ (1.9)	$ (1.6)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 6.0	$ 5.5	$ 0.4	$ 0.4
Interest Cost	5.0	6.4	1.2	1.6
Expected Return on Plan Assets	(9.2)	(10.9)	(3.8)	(3.9)
Amortization of Prior Service Credit	—	—	(3.3)	(3.2)
Amortization of Net Actuarial Loss	3.7	3.5	—	0.2
Net Periodic Benefit Cost (Credit)	$ 5.5	$ 4.5	$ (5.5)	$ (4.9)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 2.7	$ 2.6	$ 0.3	$ 0.2
Interest Cost	2.2	2.5	0.4	0.6
Expected Return on Plan Assets	(3.3)	(3.9)	(1.5)	(1.5)
Amortization of Prior Service Credit	—	—	(1.4)	(1.3)
Amortization of Net Actuarial Loss	1.5	1.4	—	0.1
Net Periodic Benefit Cost (Credit)	$ 3.1	$ 2.6	$ (2.2)	$ (1.9)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Service Cost	$ 8.4	$ 7.5	$ 0.6	$ 0.6
Interest Cost	6.4	7.6	1.4	1.9
Expected Return on Plan Assets	(10.1)	(11.7)	(4.5)	(4.7)
Amortization of Prior Service Credit	—	—	(4.0)	(3.9)
Amortization of Net Actuarial Loss	4.6	4.2	—	0.3
Net Periodic Benefit Cost (Credit)	$ 9.3	$ 7.6	$ (6.5)	$ (5.8)

Qualified Pension Contribution (Applies to all Registrants except AEPTCo and PSO)

For the qualified pension plan, discretionary contributions may be made to maintain the funded status of the plan. In the third quarter of 2020, AEP made a discretionary contribution to the qualified pension plan. The following table provides details of the contribution by Registrant:

Company	Qualified Pension Plan	
	(in millions)	
AEP	$	110.3
AEP Texas		11.3
APCo		7.0
I&M		6.4
OPCo		0.1
SWEPCo		8.9

8. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity to serve standard service offer 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 ROEs.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved ROEs.

Generation & Marketing

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

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

The tables below represent AEP's reportable segment income statement information for the three and nine months ended September 30, 2021 and 2020 and reportable segment balance sheet information as of September 30, 2021 and December 31, 2020.

Three Months Ended September 30, 2021	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 2,716.8	$ 1,195.0	$ 90.3	$ 617.4	$ 3.5	$ —	$ 4,623.0
Other Operating Segments	42.5	5.3	301.3	3.7	23.2	(376.0)	—
Total Revenues	$ 2,759.3	$ 1,200.3	$ 391.6	$ 621.1	$ 26.7	$ (376.0)	$ 4,623.0
Net Income (Loss)	$ 438.7	$ 155.9	$ 167.9	$ 99.5	$ (65.1)	$ —	$ 796.9

Three Months Ended September 30, 2020	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 2,400.1	$ 1,124.1	$ 73.4	$ 464.8	$ 4.0	$ —	$ 4,066.4
Other Operating Segments	34.7	41.2	244.5	25.2	28.6	(374.2)	—
Total Revenues	$ 2,434.8	$ 1,165.3	$ 317.9	$ 490.0	$ 32.6	$ (374.2)	$ 4,066.4
Net Income (Loss)	$ 394.2	$ 147.4	$ 139.3	$ 114.6	$ (47.3)	$ —	$ 748.2

Nine Months Ended September 30, 2021	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 7,445.9	$ 3,366.9	$ 264.6	$ 1,641.6	$ 11.6	$ —	$ 12,730.6
Other Operating Segments	111.3	24.9	882.2	50.3	43.5	(1,112.2)	—
Total Revenues	$ 7,557.2	$ 3,391.8	$ 1,146.8	$ 1,691.9	$ 55.1	$ (1,112.2)	$ 12,730.6
Net Income (Loss)	$ 938.9	$ 424.0	$ 510.7	$ 184.2	$ (108.3)	$ —	$ 1,949.5

Nine Months Ended September 30, 2020	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 6,655.4	$ 3,208.7	$ 215.7	$ 1,223.4	$ 4.7	$ —	$ 11,307.9
Other Operating Segments	98.1	98.0	662.1	82.1	67.3	(1,007.6)	—
Total Revenues	$ 6,753.5	$ 3,306.7	$ 877.8	$ 1,305.5	$ 72.0	$ (1,007.6)	$ 11,307.9
Net Income (Loss)	$ 896.8	$ 403.1	$ 373.1	$ 203.6	$ (114.6)	$ —	$ 1,762.0

	September 30, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$ 50,990.6	$ 22,171.7	$ 12,865.6	$ 2,125.8	$ 414.5	$ —	$ 88,568.2
Accumulated Depreciation and Amortization	16,647.1	4,059.9	758.1	222.8	189.1	—	21,877.0
Total Property Plant and Equipment - Net	$ 34,343.5	$ 18,111.8	$ 12,107.5	$ 1,903.0	$ 225.4	$ —	$ 66,691.2
Total Assets	$ 45,775.5	$ 21,053.1	$ 13,287.6	$ 4,387.6	$ 6,421.4 (b)	$ (4,588.1) (c)	$ 86,337.1
Long-term Debt Due Within One Year:							
Nonaffiliated	$ 1,243.0	$ 815.2	$ 52.4	$ —	$ 411.2 (d)	$ —	$ 2,521.8
Long-term Debt:							
Affiliated	65.0	—	—	—	—	(65.0)	—
Nonaffiliated	13,616.0	7,869.0	4,544.2	—	6,027.3 (d)	—	32,056.5
Total Long-term Debt	$ 14,924.0	$ 8,684.2	$ 4,596.6	$ —	$ 6,438.5 (d)	$ (65.0)	$ 34,578.3

	December 31, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$ 49,023.3	$ 21,145.0	$ 11,827.2	$ 1,910.2	$ 407.3	$ —	$ 84,313.0
Accumulated Depreciation and Amortization	15,586.2	3,879.3	595.7	166.1	184.1	—	20,411.4
Total Property Plant and Equipment - Net	$ 33,437.1	$ 17,265.7	$ 11,231.5	$ 1,744.1	$ 223.2	$ —	$ 63,901.6
Total Assets	$ 42,752.7	$ 19,765.9	$ 12,627.3	$ 3,585.9	$ 5,987.1 (b)	$ (3,961.7) (c)	$ 80,757.2
Long-term Debt Due Within One Year:							
Nonaffiliated	$ 1,034.6	$ 588.8	$ 52.3	$ —	$ 410.4 (d)	$ —	$ 2,086.1
Long-term Debt:							
Affiliated	65.0	—	—	—	—	(65.0)	—
Nonaffiliated	12,375.6	6,661.9	4,075.7	—	5,873.2 (d)	—	28,986.4
Total Long-term Debt	$ 13,475.2	$ 7,250.7	$ 4,128.0	$ —	$ 6,283.6 (d)	$ (65.0)	$ 31,072.5

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and other nonallocated costs.
(b) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(c) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.
(d) Amounts are inclusive of the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 for additional information.

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the three and nine months ended September 30, 2021 and 2020 and reportable segment balance sheet information as of September 30, 2021 and December 31, 2020.

	Three Months Ended September 30, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 79.2	$ —	$ —	$ 79.2
Sales to AEP Affiliates	297.6	—	—	297.6
Other Revenues	0.2	—	—	0.2
Total Revenues	$ 377.0	$ —	$ —	$ 377.0
Interest Income	$ 0.1	$ 40.3	$ (40.2) (a)	$ 0.2
Interest Expense	36.1	40.2	(40.2) (a)	36.1
Income Tax Expense	36.7	—	—	36.7
Net Income	$ 145.3	$ 0.1 (b)	$ —	$ 145.4

	Three Months Ended September 30, 2020			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 62.9	$ —	$ —	$ 62.9
Sales to AEP Affiliates	241.2	—	—	241.2
Total Revenues	$ 304.1	$ —	$ —	$ 304.1
Interest Income	$ —	$ 38.4	$ (38.2) (a)	$ 0.2
Interest Expense	32.7	38.2	(38.2) (a)	32.7
Income Tax Expense	31.7	—	—	31.7
Net Income	$ 117.5	$ 0.1 (b)	$ —	$ 117.6

	Nine Months Ended September 30, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 239.3	$ —	$ —	$ 239.3
Sales to AEP Affiliates	864.6	—	—	864.6
Other Revenues	0.3	—	—	0.3
Total Revenues	$ 1,104.2	$ —	$ —	$ 1,104.2
Interest Income	$ 0.1	$ 117.0	$ (116.7) (a)	$ 0.4
Interest Expense	104.5	116.6	(116.6) (a)	104.5
Income Tax Expense	115.4	—	—	115.4
Net Income	$ 445.5	$ 0.2 (b)	$ —	$ 445.7

	Nine Months Ended September 30, 2020			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 184.6	$ —	$ —	$ 184.6
Sales to AEP Affiliates	652.6	—	—	652.6
Other Revenues	0.6	—	—	0.6
Total Revenues	$ 837.8	$ —	$ —	$ 837.8
Interest Income	$ 0.9	$ 111.3	$ (109.9) (a)	$ 2.3
Interest Expense	95.1	109.9	(109.9) (a)	95.1
Income Tax Expense	82.7	0.1	—	82.8
Net Income	$ 308.0	$ 1.1 (b)	$ —	$ 309.1

	September 30, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$ 12,359.3	$ —	$ —	$ 12,359.3
Accumulated Depreciation and Amortization	730.4	—	—	730.4
Total Transmission Property – Net	$ 11,628.9	$ —	$ —	$ 11,628.9
Notes Receivable - Affiliated	$ —	$ 4,343.5	$ (4,343.5) (c)	$ —
Total Assets	$ 11,984.7	$ 4,445.3 (d)	$ (4,498.9) (e)	$ 11,931.1
Total Long-term Debt	$ 4,440.0	$ 4,393.4	$ (4,440.0) (c)	$ 4,393.4

	December 31, 2020			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$ 11,345.6	$ —	$ —	$ 11,345.6
Accumulated Depreciation and Amortization	572.8	—	—	572.8
Total Transmission Property – Net	$ 10,772.8	$ —	$ —	$ 10,772.8
Notes Receivable - Affiliated	$ —	$ 3,948.5	$ (3,948.5) (c)	$ —
Total Assets	$ 11,185.1	$ 4,084.0 (d)	$ (4,023.1) (e)	$ 11,246.0
Total Long-term Debt	$ 3,990.0	$ 3,948.5	$ (3,990.0) (c)	$ 3,948.5

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

9. DERIVATIVES AND HEDGING

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments
September 30, 2021

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	341.9	—	55.4	23.1	2.8	18.7	5.4
Natural Gas	MMBtus	28.1	—	—	—	—	—	5.2
Heating Oil and Gasoline	Gallons	7.8	2.0	1.2	0.7	1.5	0.9	1.1
Interest Rate	USD	$ 116.5	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,250.0	$ —	$ —	$ —	$ —	$ —	$ —

December 31, 2020

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	331.3	—	46.9	19.7	3.0	11.9	4.0
Natural Gas	MMBtus	26.9	—	—	—	—	—	7.9
Heating Oil and Gasoline	Gallons	6.9	1.8	1.1	0.6	1.4	0.7	0.9
Interest Rate	USD	$ 129.8	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,150.0	$ —	$ 200.0	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third-party contractual agreements and risk profiles. The Registrants netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	September 30, 2021		December 31, 2020	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in millions)			
AEP	$ 309.7	$ 38.3	$ 3.4	$ 6.8
APCo	0.6	10.7	0.4	—
I&M	0.3	17.4	1.7	—

Amounts for AEP Texas, OPCo, PSO and SWEPCo are immaterial as of September 30, 2021 and December 31, 2020, respectively.

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

AEP

	September 30, 2021					
	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)			
	(in millions)					
Current Risk Management Assets	$ 1,005.5	$ 321.1	$ 8.3	$ 1,334.9	$ (965.7)	$ 369.2
Long-term Risk Management Assets	337.3	85.8	—	423.1	(144.8)	278.3
Total Assets	1,342.8	406.9	8.3	1,758.0	(1,110.5)	647.5
Current Risk Management Liabilities	834.5	33.1	—	867.6	(761.1)	106.5
Long-term Risk Management Liabilities	234.6	14.3	28.8	277.7	(78.1)	199.6
Total Liabilities	1,069.1	47.4	28.8	1,145.3	(839.2)	306.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 273.7	$ 359.5	$ (20.5)	$ 612.7	$ (271.3)	$ 341.4

	December 31, 2020					
	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)			
	(in millions)					
Current Risk Management Assets	$ 239.1	$ 21.1	$ 5.0	$ 265.2	$ (170.5)	$ 94.7
Long-term Risk Management Assets	275.9	18.0	—	293.9	(51.7)	242.2
Total Assets	515.0	39.1	5.0	559.1	(222.2)	336.9
Current Risk Management Liabilities	193.0	54.4	3.4	250.8	(172.0)	78.8
Long-term Risk Management Liabilities	222.2	60.1	4.1	286.4	(53.6)	232.8
Total Liabilities	415.2	114.5	7.5	537.2	(225.6)	311.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 99.8	$ (75.4)	$ (2.5)	$ 21.9	$ 3.4	$ 25.3

AEP Texas

Balance Sheet Location	September 30, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.8	$ (0.8)	$ —
Long-term Risk Management Assets	0.1	(0.1)	—
Total Assets	0.9	(0.9)	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.9	$ (0.9)	$ —

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.4	$ (0.4)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.4	(0.4)	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.4	$ (0.4)	$ —

APCo

Balance Sheet Location	September 30, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 95.7	$ (48.7)	$ 47.0
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	95.9	(48.9)	47.0
Other Current Liabilities - Current Risk Management Liabilities	60.2	(58.9)	1.3
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.2	(0.2)	—
Total Liabilities	60.4	(59.1)	1.3
Total MTM Derivative Contract Net Assets	$ 35.5	$ 10.2	$ 45.7

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Hedging Contracts – Interest Rate (a)	Gross Amounts of Risk Management Assets/Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/ Liabilities Presented in the Statement of Financial Position (c)
			(in millions)		
Current Risk Management Assets	$ 38.8	$ 2.4	$ 41.2	$ (18.8)	$ 22.4
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.7	—	0.7	(0.6)	0.1
Total Assets	39.5	2.4	41.9	(19.4)	22.5
Other Current Liabilities - Current Risk Management Liabilities	19.7	3.4	23.1	(18.5)	4.6
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.6	—	0.6	(0.5)	0.1
Total Liabilities	20.3	3.4	23.7	(19.0)	4.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 19.2	$ (1.0)	$ 18.2	$ (0.4)	$ 17.8

I&M

Balance Sheet Location	September 30, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 37.8	$ (32.3)	$ 5.5
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.1	(0.1)	—
Total Assets	37.9	(32.4)	5.5
Current Risk Management Liabilities	51.9	(49.4)	2.5
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.1	(0.1)	—
Total Liabilities	52.0	(49.5)	2.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ (14.1)	$ 17.1	$ 3.0

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 17.2	$ (13.6)	$ 3.6
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.5	(0.4)	0.1
Total Assets	17.7	(14.0)	3.7
Current Risk Management Liabilities	12.1	(12.0)	0.1
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.4	(0.3)	0.1
Total Liabilities	12.5	(12.3)	0.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5.2	$ (1.7)	$ 3.5

OPCo

Balance Sheet Location	September 30, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.6	$ (0.6)	$ —
Long-term Risk Management Assets	0.1	(0.1)	—
Total Assets	0.7	(0.7)	—
Current Risk Management Liabilities	3.5	—	3.5
Long-term Risk Management Liabilities	86.9	—	86.9
Total Liabilities	90.4	—	90.4
Total MTM Derivative Contract Net Liabilities	$ (89.7)	$ (0.7)	$ (90.4)

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.3	$ (0.3)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.3	(0.3)	—
Current Risk Management Liabilities	8.7	—	8.7
Long-term Risk Management Liabilities	101.6	—	101.6
Total Liabilities	110.3	—	110.3
Total MTM Derivative Contract Net Liabilities	$ (110.0)	$ (0.3)	$ (110.3)

PSO

Balance Sheet Location	September 30, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 19.0	$ (0.5)	$ 18.5
Long-term Risk Management Assets	—	—	—
Total Assets	19.0	(0.5)	18.5
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 18.8	$ (0.3)	$ 18.5

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 10.5	$ (0.2)	$ 10.3
Long-term Risk Management Assets	—	—	—
Total Assets	10.5	(0.2)	10.3
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 10.5	$ (0.2)	$ 10.3

SWEPCo

Balance Sheet Location	September 30, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 18.1	$ (0.6)	$ 17.5
Long-term Risk Management Assets	2.1	—	2.1
Total Assets	20.2	(0.6)	19.6
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20.0	$ (0.4)	$ 19.6

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 3.4	$ (0.2)	$ 3.2
Long-term Risk Management Assets	—	—	—
Total Assets	3.4	(0.2)	3.2
Current Risk Management Liabilities	0.7	—	0.7
Long-term Risk Management Liabilities	1.0	—	1.0
Total Liabilities	1.7	—	1.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1.7	$ (0.2)	$ 1.5

(a) Derivative instruments within these categories are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The tables below present the Registrants' amount of gain (loss) recognized on risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended September 30, 2021 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ (0.9)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	128.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.9)	—	—	—	—
Purchased Electricity for Resale	0.2	—	0.1	—	—	—	—
Other Operation	0.9	0.3	0.1	0.1	0.1	0.1	0.2
Maintenance	1.1	0.2	0.2	0.1	0.2	0.1	0.1
Regulatory Assets (a)	(7.2)	—	(2.9)	(16.9)	14.9	—	0.1
Regulatory Liabilities (a)	46.5	(0.1)	14.2	1.7	0.8	14.0	12.7
Total Gain (Loss) on Risk Management Contracts	$ 169.4	$ 0.4	$ 10.8	$ (15.0)	$ 16.0	$ 14.2	$ 13.1

Location of Gain (Loss)	Three Months Ended September 30, 2020 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 0.5	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	11.5	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.3	—	—	—	—
Purchased Electricity for Resale	0.3	—	0.2	0.1	—	—	—
Other Operation	(0.4)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Maintenance	(0.8)	(0.2)	(0.1)	(0.1)	(0.2)	—	(0.1)
Regulatory Assets (a)	7.9	0.2	0.4	0.2	4.4	(0.4)	2.9
Regulatory Liabilities (a)	17.0	—	3.8	2.6	1.7	3.1	2.0
Total Gain (Loss) on Risk Management Contracts	$ 36.0	$ (0.1)	$ 4.5	$ 2.7	$ 5.8	$ 2.6	$ 4.7

Location of Gain (Loss)	Nine Months Ended September 30, 2021 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ (0.6)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	144.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.6)	—	—	—	—
Purchased Electricity for Resale	1.2	—	1.0	0.1	—	—	—
Other Operation	1.9	0.6	0.2	0.2	0.3	0.2	0.3
Maintenance	2.4	0.6	0.4	0.2	0.4	0.2	0.3
Regulatory Assets (a)	(7.8)	—	(2.9)	(22.9)	20.3	—	1.4
Regulatory Liabilities (a)	123.6	0.5	28.9	1.9	5.9	40.2	38.5
Total Gain (Loss) on Risk Management Contracts	$ 265.6	$ 1.7	$ 27.0	$ (20.5)	$ 26.9	$ 40.6	$ 40.5

Location of Gain (Loss)	Nine Months Ended September 30, 2020 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.8	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	11.1	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.4	0.1	—	—	0.1
Purchased Electricity for Resale	1.2	—	1.0	0.1	—	—	—
Other Operation	(1.4)	(0.4)	(0.2)	(0.2)	(0.3)	(0.2)	(0.2)
Maintenance	(2.2)	(0.6)	(0.3)	(0.2)	(0.4)	(0.2)	(0.3)
Regulatory Assets (a)	(8.5)	(0.3)	(0.1)	(0.2)	(9.9)	(0.6)	2.2
Regulatory Liabilities (a)	80.9	—	16.2	8.8	8.4	23.9	14.8
Total Gain (Loss) on Risk Management Contracts	$ 81.9	$ (1.3)	$ 17.0	$ 8.4	$ (2.2)	$ 22.9	$ 16.6

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.”

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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

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

The following table shows the impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Liabilities		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Liabilities	
	September 30, 2021	December 31, 2020	September 30, 2021	December 31, 2020
	(in millions)			
Long-term Debt (a) (b)	$ (965.6)	$ (995.9)	$ (22.1)	$ (51.7)

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.
(b) Amounts include $(47) million and $(53) million as of September 30, 2021 and December 31, 2020, respectively, for the fair value hedge adjustment of hedged debt obligations for which hedge accounting has been discontinued.

The pretax effects of fair value hedge accounting on income were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Fair Value Hedging Instruments (a)	$ (0.1)	$ —	$ (23.8)	$ 42.6
Fair Value Portion of Long-term Debt (a)	0.1	—	23.8	(42.6)

(a) Gain (Loss) is included in Interest Expense on the statements of income.

In June 2020, AEP terminated a $500 million notional amount interest rate swap resulting in the discontinuance of the hedging relationship. A gain of $57 million on the fair value of the hedging instrument was settled in cash and recorded within operating activities on the statements of cash flows. Subsequent to the discontinuation of hedge accounting, the remaining adjustment to the carrying amount of the hedged item of $57 million will be amortized on a straight line basis through November 2027 in Interest Expense on the statements of income.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects net income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2021 and 2020, AEP applied cash flow hedging to outstanding power derivatives and the Registrant Subsidiaries did not.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three months ended September 30, 2021, AEP applied cash flow hedging to outstanding interest rate derivatives and the Registrant Subsidiaries did not. During the three months ended September 30, 2020, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the nine months ended September 30, 2021 and 2020, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on AEP's Balance Sheets

	September 30, 2021		December 31, 2020	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ 283.9	$ (26.1)	$ (60.6)	$ (47.5)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	56.5	(2.6)	(27.1)	(5.7)

As of September 30, 2021 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 114 months and 111 months for commodity and interest rate hedges, respectively.

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

	September 30, 2021		December 31, 2020	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (1.5)	$ (1.1)	$ (2.3)	$ (1.1)
APCo	7.7	0.8	(0.8)	0.4
I&M	(7.0)	(1.6)	(8.3)	(1.6)
PSO	—	—	0.1	0.1
SWEPCo	0.8	(0.4)	(0.3)	(1.5)

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

Credit Risk

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

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

Collateral Triggering Events

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

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. AEP had derivative contracts with collateral triggering events in a net liability position as of September 30, 2021, with a total exposure of $25 million. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of September 30, 2021. The Registrants had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2020.

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

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

	September 30, 2021		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 128.2	$ —	$ 95.8
APCo	1.0	—	—
I&M	0.6	—	—
SWEPCo	—	—	—

	December 31, 2020		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 188.4	$ —	$ 169.2
APCo	4.3	—	3.5
I&M	0.5	—	0.1
SWEPCo	1.8	—	1.8

Warrants Held in Investee (Applies to AEP)

AEP holds an investment in ChargePoint, which completed an initial public offering (IPO) in February 2021 via a reverse merger with a public special purpose acquisition company. Before the IPO, AEP's interests in ChargePoint consisted of a noncontrolling equity interest of preferred shares, which were accounted for at their historical cost of $8 million as of December 31, 2020, and common share warrants. After the IPO, AEP's interests in ChargePoint consisted of a noncontrolling equity interest of common shares, which were accounted for at their fair value of $30 million as of September 30, 2021, and common share warrants. AEP recorded an unrealized gain (loss) of $(16) million and $22 million associated with the common shares for the three and nine months ended September 30, 2021, respectively, presented in Other Income (Expense) on AEP's statements of income.

Management has determined the common share warrants are derivative instruments based on the accounting guidance for "Derivatives and Hedging". As of September 30, 2021 and December 31, 2020, the warrants were valued at $16 million and $32 million, respectively, and were recorded in Deferred Charges and Other Noncurrent Assets on AEP's balance sheets.AEP recognized an unrealized loss of $10 million and $16 million associated with the warrants for the three and nine months ended September 30, 2021, respectively, presented in Other Income (Expense) on AEP's statements of income.

Management utilized a Black-Scholes options pricing model to value the warrants as of September 30, 2021 and December 31, 2020.The valuation contemplated a liquidity adjustment that resulted in the overall fair value of the warrants being categorized as Level 3 in the fair value hierarchy as of December 31, 2020. After the IPO, there was an observable publicly traded stock price to use in the Black-Scholes options pricing model, which resulted in the warrants being categorized as Level 2 as of September 30, 2021. The common shares are categorized as Level 1 based on the observable publicly traded stock price. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 10 for additional information.

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

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

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

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

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

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

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value of AEP's Equity Units (Level 1) are valued based on publicly traded securities issued by AEP.

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

	September 30, 2021		December 31, 2020	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
		(in millions)		
AEP (a)	$ 34,578.3	$ 38,925.1	$ 31,072.5	$ 37,457.0
AEP Texas	5,216.1	5,763.9	4,820.4	5,682.6
AEPTCo	4,393.4	5,074.5	3,948.5	4,984.3
APCo	4,937.8	6,067.0	4,834.1	6,391.8
I&M	3,231.1	3,790.5	3,029.9	3,775.3
OPCo	3,468.1	3,948.6	2,430.2	3,154.9
PSO	1,913.3	2,169.2	1,373.8	1,732.1
SWEPCo	3,129.9	3,534.0	2,636.4	3,210.1

(a) The fair value amounts include debt related to AEP's Equity Units and had a fair value of $1.6 billion and $1.7 billion as of September 30, 2021 and December 31, 2020, respectively. See "Equity Units" section of Note 12 for additional information.

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

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

The following is a summary of Other Temporary Investments:

	September 30, 2021			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash and Other Cash Deposits (a)	$ 77.3	$ —	$ —	$ 77.3
Fixed Income Securities – Mutual Funds (b)	141.8	1.8	—	143.6
Equity Securities – Mutual Funds	19.4	32.1	—	51.5
Total Other Temporary Investments	$ 238.5	$ 33.9	$ —	$ 272.4

	December 31, 2020			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash and Other Cash Deposits (a)	$ 68.3	$ —	$ —	$ 68.3
Fixed Income Securities – Mutual Funds (b)	120.7	2.8	—	123.5
Equity Securities – Mutual Funds	25.9	28.7	—	54.6
Total Other Temporary Investments	$ 214.9	$ 31.5	$ —	$ 246.4

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

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

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
	(in millions)			
Proceeds from Investment Sales	$ 6.0	$ 5.1	$ 15.1	$ 35.9
Purchases of Investments	12.9	22.5	26.0	39.5
Gross Realized Gains on Investment Sales	2.4	0.2	3.6	2.4
Gross Realized Losses on Investment Sales	—	—	—	0.2

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

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

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

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies debt securities in the trust funds as available-for-sale due to their long-term purpose.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI.

The following is a summary of nuclear trust fund investments:

	September 30, 2021			December 31, 2020		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 63.9	$ —	$ —	$ 25.8	$ —	$ —
Fixed Income Securities:						
United States Government	1,135.3	66.9	(6.8)	1,025.6	98.5	(7.1)
Corporate Debt	86.6	6.9	(2.0)	86.3	9.6	(1.7)
State and Local Government	36.8	0.3	(0.2)	114.3	0.9	(0.4)
Subtotal Fixed Income Securities	1,258.7	74.1	(9.0)	1,226.2	109.0	(9.2)
Equity Securities - Domestic (a)	2,287.2	1,652.8	—	2,054.7	1,400.8	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,609.8	$ 1,726.9	$ (9.0)	$ 3,306.7	$ 1,509.8	$ (9.2)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.7 billion and $1.4 billion and unrealized losses of $4 million and $9 million as of September 30, 2021 and December 31, 2020, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(in millions)			
Proceeds from Investment Sales	$ 433.9	$ 316.6	$ 1,556.6	$ 1,257.1
Purchases of Investments	436.6	318.6	1,586.3	1,290.0
Gross Realized Gains on Investment Sales	9.6	3.4	98.3	25.4
Gross Realized Losses on Investment Sales	7.0	0.5	12.5	25.2

The base cost of fixed income securities was $1.2 billion and $1.1 billion as of September 30, 2021 and December 31, 2020, respectively. The base cost of equity securities was $634 million and $654 million as of September 30, 2021 and December 31, 2020, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2021 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 292.9
After 1 year through 5 years	433.4
After 5 years through 10 years	251.5
After 10 years	280.9
Total	$ 1,258.7

Fair Value Measurements of Financial Assets and Liabilities

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

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 66.1	$ —	$ —	$ 11.2	$ 77.3
Fixed Income Securities – Mutual Funds	143.6	—	—	—	143.6
Equity Securities – Mutual Funds (b)	51.5	—	—	—	51.5
Total Other Temporary Investments	261.2	—	—	11.2	272.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	16.9	1,090.7	221.9	(1,054.0)	275.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	367.3	31.3	(34.9)	363.7
Interest Rate Hedges	—	4.9	—	—	4.9
Fair Value Hedges	—	3.4	—	—	3.4
Total Risk Management Assets	16.9	1,466.3	253.2	(1,088.9)	647.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	56.0	—	—	7.9	63.9
Fixed Income Securities:					
United States Government	—	1,135.3	—	—	1,135.3
Corporate Debt	—	86.6	—	—	86.6
State and Local Government	—	36.8	—	—	36.8
Subtotal Fixed Income Securities	—	1,258.7	—	—	1,258.7
Equity Securities – Domestic (b)	2,287.2	—	—	—	2,287.2
Total Spent Nuclear Fuel and Decommissioning Trusts	2,343.2	1,258.7	—	7.9	3,609.8
Other Investments (h)	30.3	15.9	—	—	46.2
Total Assets	$ 2,651.6	$ 2,740.9	$ 253.2	$ (1,069.8)	$ 4,575.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 8.4	$ 923.3	$ 124.1	$ (782.6)	$ 273.2
Cash Flow Hedges:					
Commodity Hedges (c)	—	38.9	0.1	(34.9)	4.1
Fair Value Hedges	—	28.8	—	—	28.8
Total Risk Management Liabilities	$ 8.4	$ 991.0	$ 124.2	$ (817.5)	$ 306.1

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 57.8	$ —	$ —	$ 10.5	$ 68.3
Fixed Income Securities – Mutual Funds	123.5	—	—	—	123.5
Equity Securities – Mutual Funds (b)	54.6	—	—	—	54.6
Total Other Temporary Investments	235.9	—	—	10.5	246.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	0.9	258.8	252.4	(190.0)	322.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	34.4	3.9	(28.5)	9.8
Interest Rate Hedges	—	2.4	—	—	2.4
Fair Value Hedges	—	2.6	—	—	2.6
Total Risk Management Assets	0.9	298.2	256.3	(218.5)	336.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	16.8	—	—	9.0	25.8
Fixed Income Securities:					
United States Government	—	1,025.6	—	—	1,025.6
Corporate Debt	—	86.3	—	—	86.3
State and Local Government	—	114.3	—	—	114.3
Subtotal Fixed Income Securities	—	1,226.2	—	—	1,226.2
Equity Securities – Domestic (b)	2,054.7	—	—	—	2,054.7
Total Spent Nuclear Fuel and Decommissioning Trusts	2,071.5	1,226.2	—	9.0	3,306.7
Other Investments (h)	—	—	31.8	—	31.8
Total Assets	$ 2,308.3	$ 1,524.4	$ 288.1	$ (199.0)	$ 3,921.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 0.9	$ 244.2	$ 167.2	$ (193.4)	$ 218.9
Cash Flow Hedges:					
Commodity Hedges (c)	—	106.1	7.6	(28.5)	85.2
Interest Rate Hedges	—	3.4	—	—	3.4
Fair Value Hedges	—	4.1	—	—	4.1
Total Risk Management Liabilities	$ 0.9	$ 357.8	$ 174.8	$ (221.9)	$ 311.6

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$ 43.9	$ —	$ —	$ —	$ 43.9
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.9	—	(0.9)	—
Total Assets	$ 43.9	$ 0.9	$ —	$ (0.9)	$ 43.9

December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Restricted Cash for Securitized Funding	$ 28.7	$ —	$ —	$ —	$ 28.7
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.4	—	(0.4)	—
Total Assets	$ 28.7	$ 0.4	$ —	$ (0.4)	$ 28.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 10.1	$ —	$ —	$ —	$ 10.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	48.9	47.0	(48.9)	47.0
Total Assets	$ 10.1	$ 48.9	$ 47.0	$ (48.9)	$ 57.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 59.3	$ 1.1	$ (59.1)	$ 1.3

December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 16.9	$ —	$ —	$ —	$ 16.9
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	19.4	19.9	(19.2)	20.1
Cash Flow Hedges:					
Interest Rate Hedges	—	2.4	—	—	2.4
Total Risk Management Assets	—	21.8	19.9	(19.2)	22.5
Total Assets	$ 16.9	$ 21.8	$ 19.9	$ (19.2)	$ 39.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 19.5	$ 0.6	$ (18.8)	$ 1.3
Cash Flow Hedges:					
Interest Rate Hedges	—	3.4	—	—	3.4
Total Risk Management Liabilities	$ —	$ 22.9	$ 0.6	$ (18.8)	$ 4.7

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 30.9	$ 7.0	$ (32.4)	$ 5.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	56.0	—	—	7.9	63.9
Fixed Income Securities:					
United States Government	—	1,135.3	—	—	1,135.3
Corporate Debt	—	86.6	—	—	86.6
State and Local Government	—	36.8	—	—	36.8
Subtotal Fixed Income Securities	—	1,258.7	—	—	1,258.7
Equity Securities - Domestic (b)	2,287.2	—	—	—	2,287.2
Total Spent Nuclear Fuel and Decommissioning Trusts	2,343.2	1,258.7	—	7.9	3,609.8
Total Assets	$ 2,343.2	$ 1,289.6	$ 7.0	$ (24.5)	$ 3,615.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 48.3	$ 3.7	$ (49.5)	$ 2.5

December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 15.1	$ 2.5	$ (13.9)	$ 3.7
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	16.8	—	—	9.0	25.8
Fixed Income Securities:					
United States Government	—	1,025.6	—	—	1,025.6
Corporate Debt	—	86.3	—	—	86.3
State and Local Government	—	114.3	—	—	114.3
Subtotal Fixed Income Securities	—	1,226.2	—	—	1,226.2
Equity Securities - Domestic (b)	2,054.7	—	—	—	2,054.7
Total Spent Nuclear Fuel and Decommissioning Trusts	2,071.5	1,226.2	—	9.0	3,306.7
Total Assets	$ 2,071.5	$ 1,241.3	$ 2.5	$ (4.9)	$ 3,310.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 12.0	$ 0.4	$ (12.2)	$ 0.2

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.7	$ —	$ (0.7)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 90.4	$ —	$ 90.4

December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ —	$ (0.3)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 110.3	$ —	$ 110.3

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 18.7	$ (0.5)	$ 18.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.2	$ (0.2)	$ —

December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 10.3	$ (0.2)	$ 10.3

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 19.8	$ (0.6)	$ 19.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.2	$ (0.2)	$ —

December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 3.3	$ (0.2)	$ 3.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 1.7	$ —	$ 1.7

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) The September 30, 2021 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $2 million in 2021 and $7 million in periods 2022-2024; Level 2 matures $20 million in 2021, $112 million in periods 2022-2024, $22 million in periods 2025-2026 and $13 million in periods 2027-2033; Level 3 matures $96 million in 2021, $18 million in periods 2022-2024, $5 million in periods 2025-2026 and $(21) million in periods 2027-2033. Risk management commodity contracts are substantially comprised of power contracts.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(f) The December 31, 2020 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 2 matures $3 million in periods 2022-2024, $11 million in periods 2025-2026 and $1 million in periods 2027-2033; Level 3 matures $47 million in 2021, $37 million in periods 2022-2024, $14 million in periods 2025-2026 and $(13) million in periods 2027-2033. Risk management commodity contracts are substantially comprised of power contracts.
(g) Substantially comprised of power contracts for the Registrant Subsidiaries.
(h) See "Warrants Held in Investee" section of Note 9 for additional information.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Three Months Ended September 30, 2021	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of June 30, 2021	$ 101.2	$ 36.6	$ 7.3	$ (105.4)	$ 22.9	$ 14.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	27.5	4.0	0.1	0.1	13.5	5.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	2.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	17.8	—	—	—	—	—
Settlements	(54.5)	(10.5)	(3.8)	0.9	(20.6)	(9.8)
Transfers into Level 3 (d) (e)	(5.8)	—	—	—	—	—
Transfers out of Level 3 (e)	(4.1)	0.1	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	44.0	15.7	(0.3)	14.0	2.7	9.0
Balance as of September 30, 2021	$ 129.0	$ 45.9	$ 3.3	$ (90.4)	$ 18.5	$ 19.6

Three Months Ended September 30, 2020	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of June 30, 2020	$ 111.6	$ 36.5	$ 4.5	$ (117.4)	$ 23.8	$ 3.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	18.7	6.4	3.3	—	3.0	1.5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	6.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	2.6	—	—	—	—	—
Settlements	(37.0)	(11.1)	(5.0)	1.3	(10.3)	(3.5)
Transfers into Level 3 (d) (e)	(1.0)	—	—	—	—	—
Transfers out of Level 3 (e)	1.1	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	3.6	(2.2)	1.0	2.9	(0.4)	2.4
Balance as of September 30, 2020	$ 106.1	$ 29.6	$ 3.8	$ (113.2)	$ 16.1	$ 3.7

Nine Months Ended September 30, 2021	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of December 31, 2020	$ 113.3	$ 19.3	$ 2.1	$ (110.3)	$ 10.3	$ 1.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	68.9	38.8	0.4	0.4	16.1	9.5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(64.1)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	35.5	—	—	—	—	—
Settlements	(113.3)	(58.2)	(2.5)	5.8	(26.4)	(13.0)
Transfers into Level 3 (d) (e)	(0.2)	—	—		—	—
Transfers out of Level 3 (e)	(26.2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	115.1	46.0	3.3	13.7	18.5	21.5
Balance as of September 30, 2021	$ 129.0	$ 45.9	$ 3.3	$ (90.4)	$ 18.5	$ 19.6

Nine Months Ended September 30, 2020	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	39.6	13.1	2.4	(1.2)	11.9	2.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(2.4)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	21.7	—	—	—	—	—
Settlements	(115.3)	(51.4)	(8.5)	6.4	(27.6)	(6.9)
Transfers into Level 3 (d) (e)	(1.1)	—	—	—	—	—
Transfers out of Level 3 (e)	5.6	0.7	0.4	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	48.1	29.5	3.7	(14.8)	16.0	6.4
Balance as of September 30, 2020	$ 106.1	$ 29.6	$ 3.8	$ (113.2)	$ 16.1	$ 3.7

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Included in cash flow hedges on the statements of comprehensive income.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

AEP

Significant Unobservable Inputs
September 30, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 145.6	$ 117.3	Discounted Cash Flow	Forward Market Price (a) (c)	$ 0.10	$ 108.40	$ 35.57
Natural Gas Contracts	9.0	—	Discounted Cash Flow	Forward Market Price (b) (c)	2.92	6.27	4.59
FTRs	98.6	6.9	Discounted Cash Flow	Forward Market Price (a) (c)	(21.95)	13.46	0.46
Total	$ 253.2	$ 124.2					

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 213.5	$ 169.7	Discounted Cash Flow	Forward Market Price (a) (c)	$ 5.33	$ 100.47	$ 32.73
Natural Gas Contracts	—	1.7	Discounted Cash Flow	Forward Market Price (b) (c)	2.18	2.77	2.40
FTRs	42.8	3.4	Discounted Cash Flow	Forward Market Price (a) (c)	(15.08)	9.66	0.19
Other Investments	31.8	—	Black-Scholes Model	Liquidity Adjustment (d)	10 %	20 %	15 %
Total	$ 288.1	$ 174.8					

APCo

Significant Unobservable Inputs
September 30, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 0.2	$ 1.1	Discounted Cash Flow	Forward Market Price	$ 26.70	$ 87.14	$ 53.61
FTRs	46.8	—	Discounted Cash Flow	Forward Market Price	0.35	13.46	1.83
Total	$ 47.0	$ 1.1					

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 1.0	$ 0.6	Discounted Cash Flow	Forward Market Price	$ 10.84	$ 41.09	$ 25.08
FTRs	18.9	—	Discounted Cash Flow	Forward Market Price	0.04	5.61	1.13
Total	$ 19.9	$ 0.6					

I&M

Significant Unobservable Inputs
September 30, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 0.2	$ 0.7	Discounted Cash Flow	Forward Market Price	$ 26.70	$ 87.14	$ 53.61
FTRs	6.8	3.0	Discounted Cash Flow	Forward Market Price	(1.85)	5.75	0.37
Total	$ 7.0	$ 3.7					

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 0.6	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 10.84	$ 41.09	$ 25.08
FTRs	1.9	0.1	Discounted Cash Flow	Forward Market Price	(1.96)	3.69	0.33
Total	$ 2.5	$ 0.4					

OPCo

Significant Unobservable Inputs
September 30, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 90.4	Discounted Cash Flow	Forward Market Price	$ 9.89	$ 81.50	$ 32.40

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 110.3	Discounted Cash Flow	Forward Market Price	$ 16.19	$ 46.98	$ 28.30

PSO

Significant Unobservable Inputs
September 30, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 18.7	$ 0.2	Discounted Cash Flow	Forward Market Price	$ (18.86)	$ 4.10	$ (2.44)

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 10.3	$ —	Discounted Cash Flow	Forward Market Price	$ (6.93)	$ 0.48	$ (1.93)

SWEPCo

Significant Unobservable Inputs
September 30, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ 9.0	$ —	Discounted Cash Flow	Forward Market Price (b)	$ 3.58	$ 6.27	$ 4.44
FTRs	10.8	0.2	Discounted Cash Flow	Forward Market Price (a)	(18.86)	4.10	(2.44)
Total	$ 19.8	$ 0.2					

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 1.7	Discounted Cash Flow	Forward Market Price (b)	$ 2.18	$ 2.77	$ 2.41
FTRs	3.3	—	Discounted Cash Flow	Forward Market Price (a)	(6.93)	0.48	(1.93)
Total	$ 3.3	$ 1.7					

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.
(c) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.
(d) Represents percentage discount applied to the publically available share price.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts, FTRs and Other Investments for the Registrants as of September 30, 2021 and December 31 2020:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)
Liquidity Adjustment	Buy	Increase (Decrease)	Lower (Higher)

11. INCOME TAXES

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

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2021 and 2020, adjusted for tax expense associated with certain discrete items.

The Registrants include the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, the Registrants recognize the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by the Registrant's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an annual estimated ETR.

The ETR for each of the Registrants are included in the following tables:

	Three Months Ended September 30, 2021							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	0.6 %	0.3 %	3.0 %	(0.3)%	1.9 %	1.2 %	5.0 %	(6.9) %
Tax Reform Excess ADIT Reversal	(8.5)%	(6.3)%	0.3 %	(14.2)%	(16.1)%	(8.9)%	(19.8)%	(4.2) %
Production and Investment Tax Credits	(4.7)%	(0.3)%	— %	(0.2)%	(2.0)%	—%	(8.9)%	(5.4) %
Flow Through	—%	0.3 %	0.3 %	0.4 %	(2.8)%	0.6 %	0.7 %	(0.2) %
AFUDC Equity	(1.2)%	(1.0)%	(2.2) %	(1.8)%	(1.0)%	(0.3)%	(0.2)%	(0.5) %
Parent Company Loss Benefit	—%	(1.1)%	(2.3) %	(1.2)%	(3.6)%	—%	—%	0.7 %
Discrete Tax Adjustments	0.2 %	—%	— %	—%	—%	—%	—%	1.2 %
Other	0.7 %	(0.1)%	0.1 %	0.3 %	0.8 %	—%	(0.1)%	(0.2) %
Effective Income Tax Rate	8.1 %	12.8 %	20.2 %	4.0 %	(1.8)%	13.6 %	(2.3)%	5.5 %

	Three Months Ended September 30, 2020							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.7 %	2.0 %	2.9 %	3.1 %	3.4 %	0.8 %	4.6 %	2.4 %
Tax Reform Excess ADIT Reversal	(11.0)%	(14.6)%	0.4 %	(22.0)%	(16.7)%	(6.7)%	(20.3)%	(7.3) %
Production and Investment Tax Credits	(4.6)%	(0.5)%	— %	—%	(1.6)%	—%	(1.1)%	(0.5) %
Flow Through	0.5 %	0.2 %	0.5 %	1.6 %	0.2 %	0.9 %	0.2 %	(1.2) %
AFUDC Equity	(1.5)%	(3.5)%	(2.6) %	(1.1)%	(0.9)%	(0.9)%	(0.6)%	(0.3) %
Parent Company Loss Benefit	—%	—%	(0.9) %	(3.1)%	(3.7)%	(0.3)%	(1.7)%	(2.0) %
Discrete Tax Adjustments (a)	(7.4)%	(3.6)%	(0.2) %	(6.6)%	2.3 %	8.4 %	(0.6)%	(0.6) %
Other	0.1 %	0.3 %	0.1 %	—%	—%	0.3 %	0.1 %	(0.6) %
Effective Income Tax Rate	(0.2)%	1.3 %	21.2 %	(7.1)%	4.0 %	23.5 %	1.6 %	10.9 %

	Nine Months Ended September 30, 2021							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	1.2 %	0.3 %	2.8 %	1.5 %	1.6 %	0.8 %	4.8 %	(3.4) %
Tax Reform Excess ADIT Reversal	(8.9)%	(7.2)%	0.3 %	(15.2)%	(17.7)%	(9.1)%	(19.8)%	(4.3) %
Production and Investment Tax Credits	(4.9)%	(0.3)%	— %	—%	(2.2)%	—%	(8.1)%	(4.6) %
Flow Through	0.2 %	0.3 %	0.3 %	1.7 %	(3.0)%	0.9 %	0.7 %	(0.2) %
AFUDC Equity	(1.1)%	(1.1)%	(1.9) %	(1.2)%	(1.0)%	(0.8)%	(0.3)%	(0.6) %
Parent Company Loss Benefit	—%	(0.7)%	(1.9) %	(1.3)%	(2.8)%	—%	—%	— %
Discrete Tax Adjustments	1.1 %	—%	— %	—%	—%	(1.3)%	(0.9)%	0.6 %
Other	0.1 %	—%	— %	0.1 %	0.4 %	0.2 %	(0.2)%	(0.1) %
Effective Income Tax Rate	8.7 %	12.3 %	20.6 %	6.6 %	(3.7)%	11.7 %	(2.8)%	8.4 %

	Nine Months Ended September 30, 2020							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.6 %	1.8 %	2.9 %	3.1 %	3.4 %	0.7 %	4.6 %	2.3 %
Tax Reform Excess ADIT Reversal	(12.1)%	(23.4)%	0.4 %	(20.8)%	(16.7)%	(8.8)%	(20.3)%	(11.5) %
Production and Investment Tax Credits	(4.5)%	(0.5)%	— %	—%	(1.6)%	—%	(1.1)%	(0.5) %
Flow Through	0.5 %	0.1 %	0.5 %	1.6 %	0.2 %	0.9 %	0.2 %	(1.2) %
AFUDC Equity	(1.5)%	(3.2)%	(2.6) %	(1.1)%	(0.9)%	(0.9)%	(0.6)%	(0.3) %
Parent Company Loss Benefit	—%	—%	(0.9) %	(3.1)%	(3.7)%	(0.3)%	(1.7)%	(1.9) %
Discrete Tax Adjustments (a)	(3.0)%	(1.6)%	(0.1) %	(2.3)%	1.8 %	2.6 %	(0.4)%	(0.3) %
Other	0.2 %	0.4 %	(0.1) %	(0.1)%	(0.1)%	0.2 %	0.1 %	(0.4) %
Effective Income Tax Rate	3.2 %	(5.4)%	21.1 %	(1.7)%	3.4 %	15.4 %	1.8 %	7.2 %

(a) The discrete tax expense is primarily attributable to the $48 million benefit recognized as a result of the 5-year net operating losses (NOL) carryback provision of the CARES Act.

Federal and State Income Tax Audit Status

The statute of limitations for the IRS to examine AEP and subsidiaries originally filed federal return has expired for tax years 2016 and earlier.In the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 through 2017 federal returns. In the first quarter of 2020, the IRS notified AEP that it was beginning an examination of these amended returns, including the NOL carryback to 2015 that originated in the 2017 return. As of September 30, 2021, the IRS has not challenged any items on these returns and the IRS is limited in their proposed adjustments to the amount AEP claimed on the amended returns. AEP has agreed to extend the statute of limitations on the 2017 tax return to December 31, 2022 to allow time for the audit to be completed and the Congressional Joint Committee on Taxation to approve the associated refund claim.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and AEP and subsidiaries are currently under examination in several state and local jurisdictions. The Registrants are no longer subject to state or local examinations by tax authorities for years before 2012. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Federal Legislation

In March 2020, the CARES Act was signed into law.The CARES Act includes tax relief provisions including a 5-year NOL carryback from years 2018-2020. In the third quarter of 2020, AEP requested a $95 million refund of taxes paid in 2014 under the 5-year NOL carryback provision of the CARES Act.AEP carried back a NOL generated on the 2019 Federal income tax return at a 21% federal corporate income tax rate to the 2014 Federal income tax return at a 35% corporate income tax rate. As a result of the change in the corporate income tax rates between the two periods, AEP realized a tax benefit of $48 million primarily at the Generation & Marketing segment in 2020.

State Legislation

In April 2021, West Virginia enacted House Bill (H.B.) 2026.H.B. 2026 changes the state income tax apportionment formula from a ratio that includes property, payroll and sales to a single sales factor apportionment regime effective for tax years beginning on or after January 1, 2022. H.B. 2026 also eliminates the "throw out" rule related to sales of tangible personal property for sales factor apportionment calculation purposes and introduces a market-based sourcing for sales of services and intangible property. In the second quarter of 2021, AEP recorded $20 million in Income Tax Expense as a result of remeasuring West Virginia deferred taxes under the new apportionment methodology. The enacted legislation does not impact AEP Texas, PSO or SWEPCo.

In May 2021, Oklahoma enacted House Bill (H.B.) 2960.H.B. 2960 reduces the Oklahoma corporate income tax rate from 6% to 4%.In the second quarter of 2021, AEP recorded a $1 million Income Tax Benefit as a result of remeasuring Oklahoma deferred taxes at the lowered statutory tax rate of 4%. The enacted legislation does not impact APCo, I&M or OPCo.

12. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

At-the-Market (ATM) Program

In 2020, AEP filed a prospectus supplement and executed an Equity Distribution Agreement, pursuant to which AEP may sell, from time to time, up to an aggregate of $1 billion of its common stock through an ATM offering program, including an equity forward sales component. The compensation paid to the selling agents by AEP may be up to 2% of the gross offering proceeds of the shares. For the nine months ended September 30, 2021, AEP issued 5,421,825 shares of common stock and received net cash proceeds of $461 million under the ATM program.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	September 30, 2021	December 31, 2020
	(in millions)	
Senior Unsecured Notes	$ 28,778.1	$ 25,116.1
Pollution Control Bonds	1,881.0	1,936.7
Notes Payable	235.1	239.1
Securitization Bonds	639.7	716.4
Spent Nuclear Fuel Obligation (a)	281.3	281.2
Junior Subordinated Notes (b)	1,629.9	1,624.1
Other Long-term Debt	1,133.2	1,158.9
Total Long-term Debt Outstanding	34,578.3	31,072.5
Long-term Debt Due Within One Year	2,521.8	2,086.1
Long-term Debt	$ 32,056.5	$ 28,986.4

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $327 million and $324 million as of September 30, 2021 and December 31, 2020, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See "Equity Units" section below for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2021 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		**(in millions)**	**(%)**	
AEP	Senior Unsecured Notes	$ 175.0	1.80	2028
AEP Texas	Senior Unsecured Notes	450.0	3.45	2051
AEPTCo	Senior Unsecured Notes	450.0	2.75	2051
APCo	Senior Unsecured Notes	500.0	2.70	2031
I&M	Notes Payable	64.9	0.93	2025
I&M	Senior Unsecured Notes	450.0	3.25	2051
OPCo	Senior Unsecured Notes	450.0	1.63	2031
OPCo	Senior Unsecured Notes	600.0	2.90	2051
PSO	Other Long-term Debt	500.0	Variable	2022
PSO	Senior Unsecured Notes	400.0	2.20	2031
PSO	Senior Unsecured Notes	400.0	3.15	2051
SWEPCo	Senior Unsecured Notes	500.0	1.65	2026
Non-Registrant:				
KPCo	Other Long-term Debt	150.0	Variable	2023
Transource Energy	Other Long-term Debt	25.9	Variable	2023
Total Issuances		$ 5,115.8		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

Company	Type of Debt		Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:			**(in millions)**	**(%)**	
AEP Texas	Securitization Bonds	$	29.7	2.85	2024
AEP Texas	Securitization Bonds		22.5	2.06	2025
APCo	Senior Unsecured Notes		350.0	4.60	2021
APCo	Pollution Control Bonds		17.5	4.63	2021
APCo	Securitization Bonds		25.4	2.01	2023
APCo	Other Long-term Debt		0.1	13.72	2026
I&M	Other Long-term Debt		200.0	Variable	2021
I&M	Pollution Control Bonds		40.0	2.05	2021
I&M	Notes Payable		1.9	Variable	2021
I&M	Notes Payable		4.5	Variable	2022
I&M	Notes Payable		5.4	Variable	2022
I&M	Notes Payable		14.3	Variable	2023
I&M	Notes Payable		12.6	Variable	2024
I&M	Notes Payable		19.6	Variable	2025
I&M	Notes Payable		7.4	0.93	2025
I&M	Other Long-term Debt		1.5	6.00	2025
OPCo	Other Long-term Debt		0.1	1.15	2028
PSO	Senior Unsecured Notes		250.0	4.40	2021
PSO	Other Long-term Debt		500.0	Variable	2022
PSO	Other Long-term Debt		0.4	3.00	2027
SWEPCo	Other Long-term Debt		1.5	4.68	2028
SWEPCo	Notes Payable		3.2	4.58	2032
Non-Registrant:					
KPCo	Senior Unsecured Notes		39.8	7.25	2021
Transource Energy	Senior Unsecured Notes		1.2	2.75	2050
Transource Energy	Senior Unsecured Notes		1.2	2.75	2050
Total Retirements and Principal Payments		$	1,549.8		

As of September 30, 2021, trustees held, on behalf of I&M, $40 million of its reacquired Pollution Control Bonds.

Long-term Debt Subsequent Event

In October 2021, I&M retired $8 million of Notes Payable related to DCC Fuel.

In October 2021, OPCo retired $500 million of Senior Unsecured Notes.

Equity Units (Applies to AEP)

2020 Equity Units

In August 2020, AEP issued 17 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $850 million. Net proceeds from the issuance were approximately $833 million. The proceeds were used to support AEP's overall capital expenditure plans.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes (notes) due in 2025 and a forward equity purchase contract which settles after three years in 2023. The notes are expected to be remarketed in 2023, at which time the interest rate will reset at the then current market rate. Investors may choose to remarket their notes to receive the remarketing proceeds and use those funds to settle the forward equity purchase contract, or accept the remarketed debt and use other funds for the equity purchase. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the principal. The Equity Units carry an annual distribution rate of 6.125%, which is comprised of a quarterly coupon rate of interest of 1.30% and a quarterly forward equity purchase contract payment of 4.825%.

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

- If the AEP common stock market price is equal to or greater than $99.95: 0.5003 shares per contract.
- If the AEP common stock market price is less than $99.95 but greater than $83.29: a number of shares per contract equal to $50 divided by the applicable market price. The holder receives a variable number of shares at $50.
- If the AEP common stock market price is less than or equal to $83.29: 0.6003 shares per contract.

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

At the time of issuance, the $850 million of notes were recorded within Long-term Debt on the balance sheets. The present value of the purchase contract payments of $121 million were recorded in Deferred Credits and Other Noncurrent Liabilities with a current portion in Other Current Liabilities at the time of issuance, representing the obligation to make forward equity contract payments, with an offsetting reduction to Paid-in Capital. The difference between the face value and present value of the purchase contract payments will be accreted to Interest Expense on the statements of income over the three year period ending in 2023. The liability recorded for the contract payments is considered non-cash and excluded from the statements of cash flows. Until settlement of the forward equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method. The maximum amount of shares AEP will be required to issue to settle the purchase contract is 10,205,100 shares (subject to an anti-dilution adjustment).

2019 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. The proceeds were used to support AEP's overall capital expenditure plans including the acquisition of Sempra Renewables LLC.

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

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

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

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

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

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 0.1% of consolidated tangible net assets as of September 30, 2021. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

Corporate Borrowing Program - AEP System (Applies to all Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries.The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC.The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2021 and December 31, 2020 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' activity and corresponding authorized borrowing limits for the nine months ended September 30, 2021 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings) from the Utility Money Pool as of September 30, 2021	Authorized Short-term Borrowing Limit	
				(in millions)			
AEP Texas	$ 355.5	$ 104.7	$ 234.7	$ 45.2	$ 47.6	$ 500.0	
AEPTCo	444.9	117.3	225.1	24.4	73.9	820.0	(a)
APCo	27.8	616.9	13.2	134.4	185.2	500.0	
I&M	166.5	368.2	117.5	76.3	80.6	500.0	
OPCo	259.2	622.9	62.8	182.5	622.9	500.0	
PSO	267.7	747.3	142.8	184.9	59.5	300.0	
SWEPCo	280.3	156.4	148.0	142.0	(122.9)	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in th Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2021 and December 31, 2020 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the nine months ended September 30, 2021 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2021
		(in millions)	
AEP Texas	$ 7.1	$ 6.9	$ 7.0
SWEPCo	2.1	2.1	2.1

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs.The amounts of outstanding loans to and borrowings from AEP as of September 30, 2021 and December 31, 2020 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets.AEPTCo's direct borrowing and lending activity with AEP and corresponding authorized borrowing limit for the nine months ended September 30, 2021 are described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30, 2021	Loans to AEP as of September 30, 2021	Authorized Short-term Borrowing Limit	
				(in millions)			
$ 14.6	$ 224.2	$ 1.6	$ 139.3	$ 8.6	$ —	$ 50.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Nine Months Ended September 30,	
	2021	2020
Maximum Interest Rate	0.40 %	2.70 %
Minimum Interest Rate	0.02 %	0.33 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30,	
Company	2021	2020	2021	2020
AEP Texas	0.33 %	1.55 %	0.27 %	0.87 %
AEPTCo	0.32 %	1.63 %	0.07 %	2.00 %
APCo	0.28 %	2.14 %	0.28 %	0.99 %
I&M	0.32 %	1.30 %	0.25 %	1.44 %
OPCo	0.27 %	1.32 %	0.15 %	2.06 %
PSO	0.34 %	1.24 %	0.06 %	1.95 %
SWEPCo	0.28 %	1.55 %	0.38 %	— %

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

	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	0.41 %	0.21 %	0.34 %	2.70 %	0.33 %	1.44 %
SWEPCo	0.41 %	0.21 %	0.34 %	2.70 %	0.33 %	1.44 %

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

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2021	0.86 %	0.25 %	0.86 %	0.25 %	0.35 %	0.34 %
2020	2.70 %	0.50 %	2.70 %	0.50 %	1.45 %	1.40 %

Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

			September 30, 2021			December 31, 2020	
Company	Type of Debt		Outstanding Amount	Interest Rate (a)		Outstanding Amount	Interest Rate (a)
			(dollars in millions)				
AEP	Securitized Debt for Receivables (b)	$	750.0	0.19%	$	592.0	0.85%
AEP	Commercial Paper		1,254.0	0.25%		1,852.3	0.29%
AEP	364-Day Term Loan		500.0	0.72%		—	—%
SWEPCo	Notes Payable		—	—%		35.0	2.55%
	Total Short-term Debt	$	2,504.0		$	2,479.3	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility which expire in September 2023 and 2024, respectively. As of September 30, 2021, the affiliated utility subsidiaries are in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2021		2020		2021		2020
	(dollars in millions)							
Effective Interest Rates on Securitization of Accounts Receivable		0.18 %		0.36 %		0.19 %		1.05 %
Net Uncollectible Accounts Receivable Written-Off	$	7.5	$	2.9	$	22.6	$	10.5

		September 30, 2021		December 31, 2020
	(in millions)			
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$	1,031.3	$	958.4
Short-term – Securitized Debt of Receivables		750.0		592.0
Delinquent Securitized Accounts Receivable		60.0		62.3
Bad Debt Reserves Related to Securitization		39.8		60.0
Unbilled Receivables Related to Securitization		224.5		296.8

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant

Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreements were:

Company	September 30, 2021	December 31, 2020
	(in millions)	
APCo	$ 131.0	$ 136.0
I&M	173.9	170.5
OPCo	377.3	398.8
PSO	147.1	85.0
SWEPCo	185.6	158.6

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2021 (a)	2020	2021 (a)	2020
	(in millions)			
APCo	$ 1.3	$ 2.0	$ 3.7	$ 5.0
I&M	2.1	3.9	5.3	9.3
OPCo	4.6	9.8	3.5	19.6
PSO	1.1	1.5	2.4	3.8
SWEPCo	1.3	2.8	4.1	6.8

(a) In 2020, an increase in allowance for doubtful accounts was recognized in response to the anticipated impact of COVID-19 on the collectability of accounts receivable, which caused an increase in fees paid by the registrants. In 2021, due to higher than expected collections of accounts receivables, allowance for doubtful accounts was adjusted resulting in the issuance of credits to offset the higher fees previously paid and to lower subsequent fees paid.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2021	2020	2021	2020
	(in millions)			
APCo	$ 342.2	$ 323.5	$ 980.6	$ 961.8
I&M	536.8	532.3	1,478.9	1,443.6
OPCo	668.4	666.0	1,867.5	1,793.0
PSO	460.1	369.2	1,068.8	961.4
SWEPCo	488.5	478.3	1,265.5	1,225.3

13. PROPERTY, PLANT AND EQUIPMENT

The disclosure in this note applies to AEP and APCo.

Asset Retirement Obligations

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal mining facilities. The discussion below summarizes significant changes to the Registrants ARO recorded in 2021 and should be read in conjunction with the Property, Plant and Equipment note within the 2020 Annual Report.

In 2020, Virginia's Governor signed House Bill 443 (HB 443) requiring APCo to close certain ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. In June 2020, APCo recorded a revision to increase estimated Glen Lyn Station ash disposal ARO liabilities by $199 million due to the enactment of HB 443. In June 2021, management completed fully designed and costed project plans for the Glen Lyn Station site and increased ash disposal ARO liabilities by an additional $79 million. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause. 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.

The following is a reconciliation of the aggregate carrying amounts of ARO for AEP and APCo:

Company	ARO as of December 31, 2020	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of September 30, 2021
			(in millions)			
AEP (a)(b)(c)(d)	$ 2,516.7	$ 77.6	$ 17.7	$ (27.6)	$ 75.1	$ 2,659.5
APCo (a)(d)	313.1	9.9	—	(5.8)	84.7	401.9

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.85 billion and $1.80 billion as of September 30, 2021 and December 31, 2020, respectively.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended September 30, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,144.3	$ 598.0	$ —	$ —	$ —	$ —	$ 1,742.3
Commercial Revenues	618.9	279.9	—	—	—	—	898.8
Industrial Revenues	566.0	95.2	—	—	—	(0.1)	661.1
Other Retail Revenues	47.5	11.1	—	—	—	—	58.6
Total Retail Revenues	2,376.7	984.2	—	—	—	(0.1)	3,360.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues	233.8	—	—	47.8	—	—	281.6
Transmission Revenues (a)	99.8	150.6	375.8	—	—	(317.4)	308.8
Renewable Generation Revenues (b)	—	—	—	24.1	—	(0.6)	23.5
Retail, Trading and Marketing Revenues (c)	—	—	—	397.1	0.1	(3.1)	394.1
Total Wholesale and Competitive Retail Revenues	333.6	150.6	375.8	469.0	0.1	(321.1)	1,008.0
Other Revenues from Contracts with Customers (b)	49.4	54.2	5.1	1.4	23.5	(40.1)	93.5
Total Revenues from Contracts with Customers	2,759.7	1,189.0	380.9	470.4	23.6	(361.3)	4,462.3
Other Revenues:							
Alternative Revenues (b)	0.5	6.4	10.7	—	—	(11.7)	5.9
Other Revenues (b) (d)	(0.9)	4.9	—	150.7	3.1	(3.0)	154.8
Total Other Revenues	(0.4)	11.3	10.7	150.7	3.1	(14.7)	160.7
Total Revenues	$ 2,759.3	$ 1,200.3	$ 391.6	$ 621.1	$ 26.7	$ (376.0)	$ 4,623.0

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $286 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $4 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Three Months Ended September 30, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 1,053.3	$ 594.8	$ —	$ —	$ —	$ —	$ 1,648.1
Commercial Revenues	559.7	259.2	—	—	—	—	818.9
Industrial Revenues	504.5	93.9	—	—	—	(0.1)	598.3
Other Retail Revenues	41.4	10.0	—	—	—	—	51.4
Total Retail Revenues	2,158.9	957.9	—	—	—	(0.1)	3,116.7
Wholesale and Competitive Retail Revenues:							
Generation Revenues	158.4	—	—	30.5	—	—	188.9
Transmission Revenues (a)	84.4	119.1	317.7	—	—	(276.9)	244.3
Renewable Generation Revenues (b)	—	—	—	15.8	—	(0.3)	15.5
Retail, Trading and Marketing Revenues (c)	—	—	—	447.5	0.9	(24.8)	423.6
Total Wholesale and Competitive Retail Revenues	242.8	119.1	317.7	493.8	0.9	(302.0)	872.3
Other Revenues from Contracts with Customers (b)	34.1	42.8	2.4	0.7	33.9	(43.7)	70.2
Total Revenues from Contracts with Customers	2,435.8	1,119.8	320.1	494.5	34.8	(345.8)	4,059.2
Other Revenues:							
Alternative Revenues (b)	(1.0)	9.3	(2.2)	—	—	6.6	12.7
Other Revenues (b) (d)	—	36.2	—	(4.5)	(2.2)	(35.0)	(5.5)
Total Other Revenues	(1.0)	45.5	(2.2)	(4.5)	(2.2)	(28.4)	7.2
Total Revenues	$ 2,434.8	$ 1,165.3	$ 317.9	$ 490.0	$ 32.6	$ (374.2)	$ 4,066.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $246 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $19 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

		Three Months Ended September 30, 2021					
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 172.5	$ —	$ 340.1	$ 231.7	$ 425.4	$ 236.8	$ 230.9
Commercial Revenues	89.1	—	146.9	143.9	190.8	120.9	145.4
Industrial Revenues	25.4	—	154.8	146.8	69.8	77.1	85.4
Other Retail Revenues	8.2	—	18.6	1.3	3.1	23.4	2.3
tal Retail Revenues	295.2	—	660.4	523.7	689.1	458.2	464.0
ıolesale Revenues:							
Generation Revenues (a)	—	—	83.7	80.2	—	7.2	77.1
Transmission Revenues (b)	131.5	360.1	35.2	8.7	19.1	10.6	37.1
tal Wholesale Revenues	131.5	360.1	118.9	88.9	19.1	17.8	114.2
Other Revenues from Contracts with Customers (c)	6.8	5.0	22.5	24.2	47.3	8.3	6.1
Total Revenues from Contracts with Customers	433.5	365.1	801.8	636.8	755.5	484.3	584.3
her Revenues:							
Alternative Revenues (d)	(0.9)	11.9	2.2	(1.1)	7.3	(0.5)	(0.2)
Other Revenues (d)	—	—	—	—	4.9	—	—
tal Other Revenues	(0.9)	11.9	2.2	(1.1)	12.2	(0.5)	(0.2)
tal Revenues	$ 432.6	$ 377.0	$ 804.0	$ 635.7	$ 767.7	$ 483.8	$ 584.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $30 million primarily relating to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $281 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $17 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended September 30, 2020						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
etail Revenues:							
Residential Revenues	$ 165.3	$ —	$ 324.2	$ 222.6	$ 429.4	$ 195.8	$ 219.4
Commercial Revenues	78.0	—	138.4	135.8	181.2	94.4	135.0
Industrial Revenues	24.9	—	139.4	139.7	69.1	55.0	83.8
Other Retail Revenues	6.9	—	17.6	1.6	3.1	18.4	2.3
otal Retail Revenues	275.1	—	619.6	499.7	682.8	363.6	440.5
holesale Revenues:							
Generation Revenues (a)	—	—	70.3	61.5	—	5.8	42.3
Transmission Revenues (b)	101.8	305.7	30.8	7.4	17.2	8.5	28.7
otal Wholesale Revenues	101.8	305.7	101.1	68.9	17.2	14.3	71.0
Other Revenues from Contracts with Customers (c)	15.2	3.0	16.1	17.7	27.6	4.8	5.6
Total Revenues from Contracts with Customers	392.1	308.7	736.8	586.3	727.6	382.7	517.1
ther Revenues:							
Alternative Revenues (d)	(0.7)	(4.6)	(1.1)	0.4	10.0	(0.5)	0.2
Other Revenues (d)	40.6	—	—	—	3.4	—	—
otal Other Revenues	39.9	(4.6)	(1.1)	0.4	13.4	(0.5)	0.2
otal Revenues	$ 432.0	$ 304.1	$ 735.7	$ 586.7	$ 741.0	$ 382.2	$ 517.3

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $28 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $243 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $15 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
etail Revenues:							
Residential Revenues	$ 3,016.2	$ 1,641.2	$ —	$ —	$ —	$ —	$ 4,657.4
Commercial Revenues	1,642.0	804.1	—	—	—	—	2,446.1
Industrial Revenues	1,602.5	283.8	—	—	—	(0.5)	1,885.8
Other Retail Revenues	125.9	32.4	—	—	—	—	158.3
tal Retail Revenues	6,386.6	2,761.5	—	—	—	(0.5)	9,147.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	757.1	—	—	119.4	—	—	876.5
Transmission Revenues (a)	267.3	420.7	1,092.1	—	—	(901.5)	878.6
Renewable Generation Revenues (b)	—	—	—	66.7	—	(1.7)	65.0
Retail, Trading and Marketing Revenues (c)	—	—	—	1,325.6	0.6	(48.5)	1,277.7
Total Wholesale and Competitive Retail Revenues	1,024.4	420.7	1,092.1	1,511.7	0.6	(951.7)	3,097.8
Other Revenues from Contracts with Customers (b)	136.1	149.3	12.5	4.9	46.1	(87.9)	261.0
Total Revenues from Contracts with Customers	7,547.1	3,331.5	1,104.6	1,516.6	46.7	(1,040.1)	12,506.4
ther Revenues:							
Alternative Revenues (b)	10.7	46.1	42.2	—	—	(63.5)	35.5
Other Revenues (b) (d)	(0.6)	14.2	—	175.3	8.4	(8.6)	188.7
tal Other Revenues	10.1	60.3	42.2	175.3	8.4	(72.1)	224.2
tal Revenues	$ 7,557.2	$ 3,391.8	$ 1,146.8	$ 1,691.9	$ 55.1	$ (1,112.2)	$ 12,730.6

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $835 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $49 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Nine Months Ended September 30, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
etail Revenues:							
Residential Revenues	$ 2,789.1	$ 1,610.6	$ —	$ —	$ —	$ —	$ 4,399.7
Commercial Revenues	1,523.6	792.4	—	—	—	—	2,316.0
Industrial Revenues	1,508.7	290.4	—	—	—	(0.5)	1,798.6
Other Retail Revenues	118.2	32.1	—	—	—	—	150.3
tal Retail Revenues	5,939.6	2,725.5	—	—	—	(0.5)	8,664.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	447.4	—	—	106.1	—	—	553.5
Transmission Revenues (a)	248.4	341.6	937.7	—	—	(741.7)	786.0
Renewable Generation Revenues (b)	—	—	—	50.7	—	(1.2)	49.5
Retail, Trading and Marketing Revenues (c)	—	—	—	1,133.8	(5.7)	(80.7)	1,047.4
Total Wholesale and Competitive Retail Revenues	695.8	341.6	937.7	1,290.6	(5.7)	(823.6)	2,436.4
Other Revenues from Contracts with Customers (b)	124.1	112.3	17.5	1.7	84.4	(115.7)	224.3
Total Revenues from Contracts with Customers	6,759.5	3,179.4	955.2	1,292.3	78.7	(939.8)	11,325.3
ther Revenues:							
Alternative Revenues (b)	(6.0)	49.2	(77.4)	—	—	3.5	(30.7)
Other Revenues (b) (d)	—	78.1	—	13.2	(6.7)	(71.3)	13.3
tal Other Revenues	(6.0)	127.3	(77.4)	13.2	(6.7)	(67.8)	(17.4)
tal Revenues	$ 6,753.5	$ 3,306.7	$ 877.8	$ 1,305.5	$ 72.0	$ (1,007.6)	$ 11,307.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $725 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $81 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Nine Months Ended September 30, 2021						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 423.7	$ —	$ 1,025.0	$ 624.4	$ 1,217.5	$ 516.4	$ 547.1
Commercial Revenues	265.2	—	409.5	384.5	538.9	286.8	385.4
Industrial Revenues	81.6	—	433.4	418.9	202.2	202.1	247.1
Other Retail Revenues	23.1	—	51.7	3.9	9.4	58.2	7.2
tal Retail Revenues	793.6	—	1,919.6	1,431.7	1,968.0	1,063.5	1,186.8
ıolesale Revenues:							
Generation Revenues (a)	—	—	231.2	248.1	—	6.8	326.2
Transmission Revenues (b)	364.5	1,045.2	94.1	25.3	56.2	28.8	94.5
tal Wholesale Revenues	364.5	1,045.2	325.3	273.4	56.2	35.6	420.7
Other Revenues from Contracts with Customers (c)	35.4	12.5	43.6	81.9	113.8	24.8	17.7
Total Revenues from Contracts with Customers	1,193.5	1,057.7	2,288.5	1,787.0	2,138.0	1,123.9	1,625.2
her Revenues:							
Alternative Revenues (d)	1.8	46.5	9.5	(3.0)	44.3	0.5	5.1
Other Revenues (d)	—	—	—	—	14.2	—	—
tal Other Revenues	1.8	46.5	9.5	(3.0)	58.5	0.5	5.1
tal Revenues	$ 1,195.3	$ 1,104.2	$ 2,298.0	$ 1,784.0	$ 2,196.5	$ 1,124.4	$ 1,630.3

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $90 million primarily relating to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $823 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $46 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2020						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 447.8	$ —	$ 954.4	$ 610.8	$ 1,162.6	$ 463.5	$ 498.7
Commercial Revenues	285.2	—	390.6	376.0	507.3	247.8	351.2
Industrial Revenues	91.4	—	415.0	408.2	199.1	170.8	245.9
Other Retail Revenues	22.3	—	50.9	5.0	9.8	51.2	6.6
Total Retail Revenues	846.7	—	1,810.9	1,400.0	1,878.8	933.3	1,102.4
Wholesale Revenues:							
Generation Revenues (a)	—	—	185.3	215.5	—	9.9	106.7
Transmission Revenues (b)	290.4	902.6	91.5	22.1	51.1	20.2	87.5
Total Wholesale Revenues	290.4	902.6	276.8	237.6	51.1	30.1	194.2
Other Revenues from Contracts with Customers (c)	33.4	17.5	46.8	60.6	78.9	23.2	21.1
Total Revenues from Contracts with Customers	1,170.5	920.1	2,134.5	1,698.2	2,008.8	986.6	1,317.7
Other Revenues:							
Alternative Revenues (d)	(0.3)	(82.3)	(11.9)	5.4	49.6	1.5	0.5
Other Revenues (d)	86.9	—	—	—	13.3	—	—
Total Other Revenues	86.6	(82.3)	(11.9)	5.4	62.9	1.5	0.5
Total Revenues	$ 1,257.1	$ 837.8	$ 2,122.6	$ 1,703.6	$ 2,071.7	$ 988.1	$ 1,318.2

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $85 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $715 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $49 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of September 30, 2021. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2021	2022-2023	2024-2025	After 2025	Total
			(in millions)		
AEP	$ 314.9	$ 199.3	$ 160.3	$ 161.5	$ 836.0
AEP Texas	132.7	—	—	—	132.7
AEPTCo	331.7	—	—	—	331.7
APCo	44.9	34.5	26.6	11.6	117.6
I&M	10.0	11.5	8.8	4.5	34.8
OPCo	22.2	10.1	—	—	32.3
PSO	3.5	—	—	—	3.5
SWEPCo	10.1	—	—	—	10.1

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have material contract assets as of September 30, 2021 and December 31, 2020.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of September 30, 2021 and December 31, 2020.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrant Subsidiaries' balance sheets within the Accounts Receivable - Customers line item. The Registrant Subsidiaries' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of September 30, 2021 and December 31, 2020. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Company	September 30, 2021	December 31, 2020
	(in millions)	
AEPTCo	$ 96.4	$ 81.0
APCo	64.1	52.7
I&M	24.6	34.8
OPCo	44.5	45.9
PSO	17.7	7.8
SWEPCo	19.9	11.2

15. SUBSEQUENT EVENTS

The disclosure in this note applies to AEP and AEPTCo.

Disposition of KPCo and KTCo

In October 2021, AEP entered into a Stock Purchase Agreement to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value. The sale is subject to regulatory approvals from the FERC, the KPSC, clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and clearance from the Committee on Foreign Investment in the United States.

KPCo currently operates and owns a 50% interest in the 1,560 MW coal-fired Mitchell Power Plant (Mitchell Plant) with the remaining 50% owned by WPCo. The Stock Purchase Agreement is further contingent upon approval by the KPSC, WVPSC and FERC of a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo will replace KPCo as the operator of the Mitchell Plant and KPCo employees at the Mitchell Plant will become employees of WPCo at closing of the transaction. Under the proposed Ownership Agreement, WPCo is obligated to purchase KPCo's 50% interest in the Mitchell Plant on December 31, 2028 unless KPCo and WPCo have agreed to retire the Mitchell Plant earlier or, absent such agreement, if WPCo elects prior to December 31, 2027 to retire the Mitchell Plant on December 31, 2028. The Ownership Agreement provides that the purchase price for KPCo's 50% ownership interest in the Mitchell Plant will be determined through the mutual agreement of WPCo and KPCo (subject to approval from the KPSC and WVPSC) or through a fair market valuation determination conducted by independent appraisals if KPCo and WPCo are unable to reach agreement as to the purchase price.

The sale is expected to close in the second quarter of 2022 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction.

AEP expects to receive approximately $1.45 billion in cash, net of taxes and transaction fees.

The major classes of KPCo and KTCo's assets and liabilities as presented on the balance sheets of AEP and AEPTCo as of September 30, 2021 are shown in the table below.

	September 30, 2021	
	AEP	AEPTCo
	(in millions)	
Assets:		
Accounts Receivable and Accrued Unbilled Revenues	$ 24.7	$ 1.6
Fuel, Materials and Supplies	26.5	—
Property, Plant and Equipment, Net	2,264.6	164.5
Regulatory Assets	501.7	—
Other Classes of Assets that are not Major	43.8	0.3
Total Assets	$ 2,861.3	$ 166.4
Liabilities:		
Accounts Payable	$ 51.2	$ 1.5
Long-term Debt Due Within One Year	125.0	—
Customer Deposits	31.9	—
Deferred Income Taxes	448.3	14.9
Long-term Debt	978.0	—
Regulatory Liabilities and Deferred Investment Tax Credits	146.5	7.5
Other Classes of Liabilities that are not Major	93.2	4.2
Total Liabilities	$ 1,874.1	$ 28.1

CONTROLS AND PROCEDURES

During the third quarter of 2021, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of September 30, 2021, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2021 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see "Commitments, Guarantees and Contingencies," of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2020 includes a detailed discussion of risk factors.As of September 30, 2021, the risk factors appearing in AEP's 2020 Annual Report are supplemented and updated as follows:

The rate of taxes imposed on AEP could change. (Applies to all Registrants)

AEP is subject to income taxation at the federal level and by certain states and municipalities. In determining AEP's income tax liability for these jurisdictions, management monitors changes to the applicable tax laws and related regulations. While management believes it is in compliance with current prevailing laws, one or more taxing jurisdictions could seek to impose incremental or new taxes on the company. In addition, as a result of the most recent presidential and congressional elections in the United States, there could be significant changes in tax law and regulations that could result in additional federal income taxes being imposed on AEP. Any adverse developments in these laws or regulations, including legislative changes, judicial holdings or administrative interpretations, could have a material and adverse effect on financial condition and results of operations.

Failure to attract and retain an appropriately qualified workforce could harm results of operations. (Applies to all Registrants)

Certain events, such as an aging workforce without appropriate replacements, employee reaction to comply with potential COVID-19 vaccination mandates, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include potential higher rates of existing employee departures, lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs, safety costs and costs of compliance with COVID-19 vaccination or testing mandates, may rise.Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate the business. If AEP is unable to successfully attract and retain an appropriately qualified workforce, future net income and cash flows may be reduced.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations.The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act.Exhibit 95 “Mine Safety Disclosure Exhibit” contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended September 30, 2021.

Item 5. Other Information

None.

Item 6. Exhibits

The documents designated with an (*) below have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof.

Exhibit	Description	Previously Filed as Exhibit to:
AEPTCo‡ File No. 333-217143		
4	Company Order and Officer's Certificate between AEP Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A. as Trustee dated August 4, 2021 establishing terms of the 2.75% Senior Notes, Series N, due 2051	Form 8-K dated August 4, 2021 Exhibit 4(a)
OPCo‡ File No.1-6543		
4	Company Order and Officer's Certificate between Ohio Power Company and The Bank of New York Mellon Trust Company, N.A. as Trustee dated September 9, 2021 establishing terms of the 2.90% Senior Notes, Series R, due 2051	Form 8-K dated September 13, 2021 Exhibit 4(a)
PSO‡ File No. 0-343		
4	Tenth Supplemental Indenture between Public Service Company of Oklahoma and The Bank of New York Mellon Trust Company, N.A. as Trustee dated August 1, 2021 establishing terms of the 2.20% Senior Notes, Series J, due 2031 and the 3.15% Senior Notes Series K, due 2051	Form 8-K dated August 12, 2021 Exhibit 4(a)

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
4	Company Order and Officer's Certificate between American Electric Power Company, Inc. and The Bank of New York Mellon Trust Company, N.A. as Trustee dated August 3, 2021 establishing terms of the 1.80% Senior Notes, Series 2021A due 2028	X							
10	Stock Purchase Agreement by and among American Electric Power Company, Inc., AEP Transmission Company, LLC and Liberty Utilities Co. dated as of October 26, 2021	X		X					
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
95	Mine Safety Disclosures								X
101.INS	XBRL Instance Document	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.							
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.							

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TEXAS INC.
AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 28, 2021