Appendix A to the
Proxy Statement

American Electric Power

2023 Annual Report

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

AMERICAN ELECTRIC POWER®

BOUNDLESS ENERGY℠

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CONTENTS

Glossary of Terms	3
Forward-Looking Information	8
AEP Common Stock Information	10
Management’s Discussion and Analysis of Financial Condition and Results of Operations	11
Report of Independent Registered Public Accounting Firm	53
Management’s Report on Internal Control Over Financial Reporting	56
Consolidated Statements of Income	57
Consolidated Statements of Comprehensive Income (Loss)	58
Consolidated Statements of Changes in Equity	59
Consolidated Balance Sheets	60
Consolidated Statements of Cash Flows	62
Index of Notes to Financial Statements of Registrants	63
Corporate and Shareholder Information	205
Executive Leadership Team	206

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 East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP Energy Supply, LLC	A nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
AEP OnSite Partners	A division of AEP Energy Supply, LLC that builds, owns, operates and maintains customer solutions utilizing existing and emerging distributed technologies.
AEP Renewables	A division of AEP Energy Supply, LLC that develops and/or acquires large scale renewable projects that are backed with long-term contracts with creditworthy counter parties.
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 Texas engages in the transmission and distribution of electric power to retail customers in west, central and southern Texas.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Wind Holdings, LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
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.
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.
AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns transmission operations joint ventures and AEPTCo.
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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APTCo	AEP Appalachian Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
ATM	At-the-Market.

Term	Meaning
BHE	Berkshire Hathaway Energy.
CAA	Clean Air Act.
CCR	Coal Combustion Residual.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,296 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.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSAPR	Cross-State Air Pollution Rule.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII, DCC Fuel XVIII and DCC Fuel XIX consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DIR	Distribution Investment Rider.
DOE	U. S. Department of Energy.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
ENEC	Expanded Net Energy Cost.
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.
GHG	Greenhouse gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IMTCo	AEP Indiana Michigan Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
IRP	Integrated Resource Plan.

Term	Meaning
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary. KGPCo provides electric service to retail customers in Kingsport, Tennessee and eight neighboring communities in northeastern Tennessee.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
kV	Kilovolt.
KWh	Kilowatt-hour.
Liberty	Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corporation.
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.
Mitchell Plant	A two unit, 1,560 MW coal-fired power plant located in Moundsville, West Virginia. The plant is jointly owned by KPCo and WPCo.
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.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,484 MWs of wind generation.
NERC	North American Electric Reliability Corporation.
NMRD	New Mexico Renewable Development, LLC.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NOL	Net operating losses.
NOLC	Net operating loss carryforwards.
NO_x	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OPCo	Ohio Power Company, an AEP electric utility subsidiary. OPCo engages in the transmission and distribution of electric power to retail customers in Ohio.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.

Term	Meaning
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSA	Purchase and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated VIE for AEP and SWEPCo.
Santa Rita East	Santa Rita East Wind Holdings, LLC, a consolidated VIE whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas in which AEP owns an 85% interest.
SEC	U.S. Securities and Exchange Commission.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019 (subsequently renamed as AEP Wind Holdings LLC), consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
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. SWEPCo engages in the generation, transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
SWTCo	AEP Southwestern Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.

Term	Meaning
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.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
Transition Funding	AEP Texas Central Transition Funding III LLC, a wholly-owned subsidiary of AEP Texas and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to restructuring legislation in Texas.
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 998 MWs of wind generation in Oklahoma.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.
WVPSC	Public Service Commission of West Virginia.
WVTCo	AEP West Virginia Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- The economic impact of increased global trade tensions including the conflicts in Ukraine and the Middle East, and the adoption or expansion of economic sanctions or trade restrictions.
- Inflationary or deflationary interest rate trends.
- Volatility and disruptions in financial markets precipitated by any cause, including failure to make progress on federal budget or debt ceiling matters or instability in the banking industry; 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 (i) if expected sources of capital such as proceeds from the sale of assets, subsidiaries and tax credits and anticipated securitizations do not materialize or do not materialize at the level anticipated, and (ii) 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.
- Limitations or restrictions on the amounts and types of insurance available to cover losses that might arise in connection with natural disasters or operations.
- 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 transition from fossil generation and 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, cost caps imposed by regulators and other operational commitments to regulatory commissions and customers for renewable generation projects, and to recover all related costs.
- The impact of pandemics and any associated disruption of AEP's business operations due to impacts on economic or market conditions, costs of compliance with potential government regulations, electricity usage, supply chain issues, customers, service providers, vendors and suppliers.
- New legislation, litigation or 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.
- The impact of federal tax legislation on results of operations, financial condition, cash flows or credit ratings.
- The risks before, during and after generation of electricity associated with the fuels used or the byproducts and wastes of such fuels, including coal ash and SNF.
- 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 or regulatory proceedings or investigations.
- The ability to efficiently manage 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.

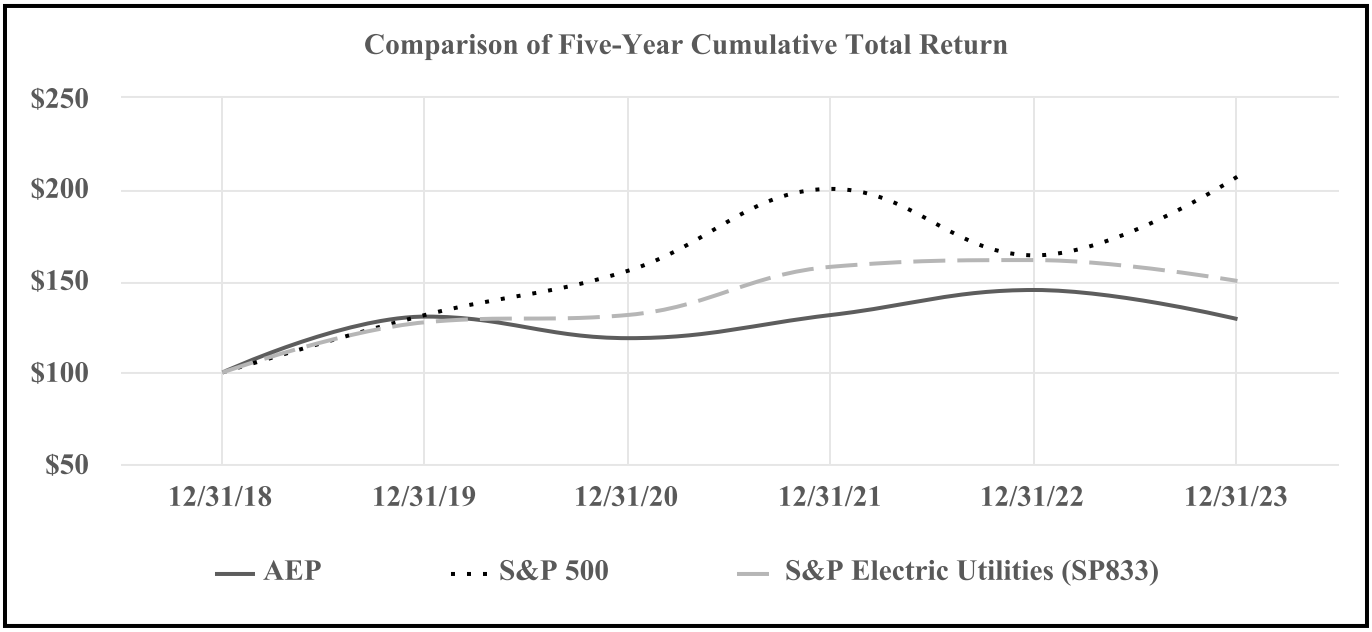
- The impact of changing expectations and demands of customers, regulators, investors and stakeholders, including focus on environmental, social and governance concerns.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.
- Changes in the creditworthiness 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 and military conflicts, the effects of terrorism (including increased security costs), embargoes, wildfires, cybersecurity threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

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

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

AEP COMMON STOCK INFORMATION

AEP common stock is principally traded using the trading symbol "AEP" on the NASDAQ Stock Market. As of December 31, 2023, AEP had 49,023 registered shareholders. The performance graph below compares the cumulative total return among AEP, the S&P 500 Index and the S&P Electric Utilities (SP833) Index over a five year period. The performance graph assumes an initial investment of $100 on December 31, 2018 and that all dividends were reinvested.



Source: S&P Dow Jones Indices LLC. Data as of December 31, 2023. Past performance is no guarantee of future results. Chart provided for illustrative purposes.

EXECUTIVE OVERVIEW

Company Overview

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

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

- Approximately 225,000 circuit miles of distribution lines that deliver electricity to 5.6 million customers.
- Approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the eastern United States.
- Approximately 23,000 MWs of regulated owned generating capacity as of December 31, 2023, one of the largest complements of generation in the United States.

AEP CONSOLIDATED RESULTS OF OPERATIONS

2023 Compared to 2022

Earnings Attributable to AEP Common Shareholders decreased from $2.3 billion in 2022 to $2.2 billion in 2023 primarily due to:

- A decrease in weather-related sales volumes.
- An increase in interest expense due to higher interest rates and debt balances.
- Unfavorable mark-to-market economic hedge activity driven by a decrease in commodity prices.
- A loss on the sale of the competitive contracted renewables portfolio in 2023.
- Unfavorable regulatory decisions in Texas, West Virginia and at FERC.
- A gain on the sale of mineral rights in 2022.

These decreases were partially offset by:

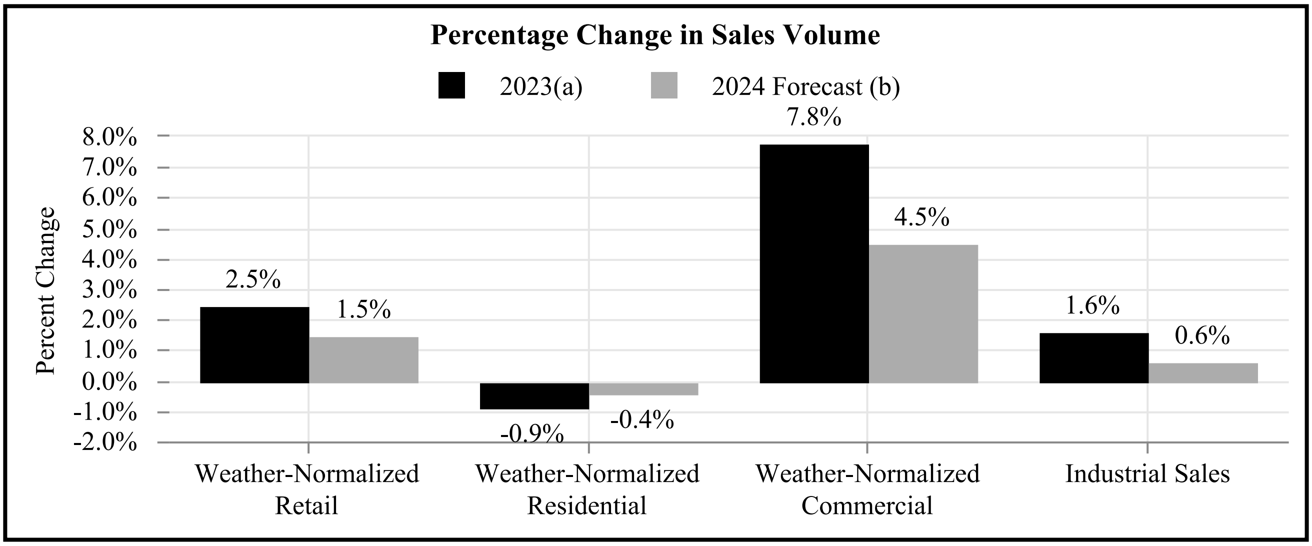
- Favorable rate proceedings in AEP's various jurisdictions.
- Investment in transmission assets, which resulted in higher revenues and income.
- A loss related to the expected sale of the Kentucky Operations in 2022. The expected sale was terminated in April 2023.
- An impairment of AEP's equity investment in Flat Ridge 2 in 2022.

See "Results of Operations" section for additional information by operating segment.

Customer Demand

AEP's weather-normalized retail sales volumes for the year ended December 31, 2023 increased by 2.5% from the year ended December 31, 2022. Weather-normalized residential sales decreased 0.9% for the year ended December 31, 2023 compared to the year ended December 31, 2022. Weather-normalized commercial sales increased by 7.8% in 2023 compared to 2022. The increase in commercial sales was primarily due to new data center loads and economic development. AEP's 2023 industrial sales volumes increased 1.6% compared to 2022. The growth in industrial sales was spread across many industries.

In 2024, AEP anticipates weather-normalized retail sales volumes will increase by 1.5%. Weather-normalized residential sales volumes are projected to decrease by 0.4% in 2024, while weather-normalized commercial sales volumes are projected to increase by 4.5%. The projected increase in commercial sales volumes is driven by new loads associated with data centers and cryptocurrency operations. Finally, AEP projects the industrial sales volumes to increase by 0.6% in 2024.



(a) Percentage change for the year ended December 31, 2023 as compared to the year ended December 31, 2022.
(b) Forecasted percentage change for the year ended December 31, 2024 compared to the year ended December 31, 2023.

Supply Chain Disruption and Inflation

The Registrants have experienced certain supply chain disruptions driven by several factors including international tensions and the ramifications of regional conflict, increased demand due to the economic recovery from the pandemic, inflation, 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 and have contributed to higher prices for fuel, materials, labor, equipment and other needed commodities. Management has implemented risk mitigation strategies in an attempt to mitigate the impacts of these supply chain disruptions.

The United States economy has experienced a significant level of inflation that has contributed to increased uncertainty in the outlook of near-term economic activity, including whether the pace of inflation will continue to moderate. A prolonged continuation or a further increase in the severity of supply chain and inflationary disruptions could result in additional increases in the cost of certain goods, services and cost of capital and further extend lead times which could reduce future net income and cash flows and impact financial condition.

2023 SIGNIFICANT DEVELOPMENTS AND TRANSACTIONS

Disposition of the Competitive Contracted Renewables Portfolio

In February 2022, AEP management announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio (the portfolio) within the Generation & Marketing segment. In late January 2023, AEP received final bids from interested parties. In February 2023, AEP's Board of Directors approved management's plan to sell the portfolio and AEP signed an agreement with a nonaffiliated party.

In August 2023, AEP completed the sale of the entire portfolio to the nonaffiliated party and received cash proceeds of approximately $1.2 billion, net of taxes and transaction costs. AEP recorded a pretax loss of approximately $93 million ($73 million after-tax) for the year ended December 31, 2023 related to the sale. See the "Disposition of the Competitive Contracted Renewables Portfolio" section of Note 7 for additional information.

Planned Sale of AEP Energy and AEP Onsite Partners

AEP management has continued a strategic evaluation of AEP's portfolio of businesses with a focus on core regulated utility operations, risk mitigation and simplification. As a result of these efforts, the following decisions have been made with respect to AEP Energy and AEP Onsite Partners.

AEP Energy

In October 2022, AEP initiated a strategic evaluation for its ownership in AEP Energy, a wholly-owned retail energy supplier that supplies electricity and/or natural gas on a price risk managed basis to residential, commercial and industrial customers. AEP Energy provides various energy solutions in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy had approximately 929,000 customer accounts as of December 31, 2023. In April 2023, AEP management completed the strategic evaluation of AEP Energy and initiated a sales process. The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in the first half of 2024. Depending on the outcome of the sales process, it could reduce future net income and impact financial condition.

AEP Onsite Partners

In April 2023, AEP also made a decision to include AEP Onsite Partners in a sales process. AEP OnSite Partners targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions. As of December 31, 2023, AEP OnSite Partners owned projects located in 22 states, including approximately 195 MWs of installed solar capacity and two solar projects under construction totaling approximately 4 MWs. As of December 31, 2023, the net book value of these assets was $352 million. The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in the first half of 2024. If AEP is unable to recover the net book value of these assets as part of the sale process, it could reduce future net income and impact financial condition.

AEP Onsite Partners also owns a 50% interest in NMRD totaling $101 million accounted for as an equity method investment. The NMRD portfolio consists of 9 operating solar projects totaling 185 MWs and 6 projects totaling 440 MWs in development. Separate from the remainder of AEP Onsite Partners, AEP and the joint owner agreed to a joint sales process for their respective interests in NMRD.

In December 2023, AEP and the joint owner signed an agreement to sell NMRD to a nonaffiliated third party for $230 million. AEP expects to receive cash proceeds of $104 million, net of taxes, transaction fees and other customary closing adjustments. AEP recorded a pretax loss of $19 million in the fourth quarter of 2023 as a result of entering into the sales agreement. The transaction has received all required regulatory approvals and is expected to close in the first quarter of 2024. See the "NMRD" section of Note 7 for additional information.

Planned Sale and Strategic Evaluation of Certain Transmission Joint Ventures

In April 2023, AEP also initiated a strategic evaluation for its ownership in certain transmission joint ventures in the AEP Transmission Holdco segment including Pioneer Transmission, LLC, Prairie Wind Transmission, LLC and Transource Energy. In July 2023, AEP made a decision to initiate a sales process for its investment in Pioneer Transmission, LLC and Prairie Wind Transmission, LLC. In February 2024, AEP management determined it would retain its ownership of its investment in Pioneer Transmission, LLC and Prairie Wind Transmission, LLC. As of December 31, 2023, AEP's investment in Pioneer Transmission, LLC and Prairie Wind Transmission, LLC was $46 million and $19 million, respectively.

As of December 31, 2023, the net book value of Transource Energy was $289 million inclusive of $39 million related to noncontrolling interest on AEP's balance sheet. AEP management recently completed its strategic review and determined it would retain this business due to its fit within the goals and objectives of AEP and its overall leadership role in the U.S. electric transmission space.

Termination of Planned Disposition of KPCo and KTCo

In October 2021, AEP entered into a Stock Purchase Agreement (SPA) 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 SPA was subsequently amended in September 2022 to reduce the purchase price to approximately $2.646 billion. An impairment of $363 million was recorded for the year ended December 31, 2022. The sale required approval from the KPSC and from the FERC under Section 203 of the Federal Power Act. The SPA contained certain termination rights if the closing of the sale did not occur by April 26, 2023.

In May 2022, the KPSC approved the sale of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. In December 2022, the FERC issued an order denying, without prejudice, authorization of the proposed sale stating the applicants failed to demonstrate the proposed transaction will not have an adverse effect on rates. In February 2023, a new filing for approval under Section 203 of the Federal Power Act was submitted. In March 2023, the KPSC and other intervenors made filings recommending the FERC reject AEP and Liberty's new Section 203 application seeking approval of the sale.

As a result of delays in the anticipated timing of the closing of the transaction and other factors, AEP recorded a $363 million pretax loss on the expected sale of the Kentucky Operations for the year ended December 31, 2022. In April 2023, AEP, AEPTCo and Liberty entered into a Mutual Termination Agreement (Termination Agreement) terminating the SPA. The parties entered into the Termination Agreement as all of the conditions precedent to closing the sale could not be satisfied prior to April 26, 2023. Upon termination of the sale and reverting to a held and used model, in the first quarter of 2023, AEP reversed $28 million of expected transaction costs included in the $363 million pretax loss and was required to present its investment in the Kentucky Operations at the lower of fair value or historical carrying value which resulted in a $335 million reduction recorded in Property, Plant and Equipment. The reduced investment in KPCo's assets is being amortized over the 30-year average useful life of the KPCo assets.

Renewable Generation

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

Significant Renewable Generation Placed Into Service

In 2023, AEP acquired and placed into service 159 MWs of owned renewable generation facilities totaling approximately $155 million.

Significant Approved Renewable Generation Filings

AEP has received regulatory approvals from various state regulatory commissions to acquire approximately 2,811 MWs of owned renewable generation facilities, totaling approximately $6.6 billion, in addition to 377 MWs of renewable purchase power agreements, as included in the following table:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	Year End 2024 through Year End 2026	PPA	204
APCo	Wind	Year End 2025 through Year End 2026	Owned	347
I&M	Solar	Year End 2025	PPA	100
I&M	Solar	Year End 2026	Owned	469
PSO	Solar	Year End 2025	Owned	443
PSO	Wind	Year End 2025 through Year End 2026	Owned	553
SWEPCo (a)	Solar	Year End 2025 through Year End 2027	Owned/PPA	273
SWEPCo (a)	Wind	Year End 2024 through Year End 2025	Owned	799
Total Approved Renewable Projects				3,188

(a) Includes approvals by the APSC and LPSC for 999 MWs of owned projects. Additionally, the LPSC approved the flex-up option, allowing SWEPCo to provide additional service to Louisiana customers and recover the portion of the projects denied by the PUCT.

Significant Renewable Generation Requests for Proposal (RFP)

As part of AEP's transition to diversify the company's regulated generation resources and build its renewable generation portfolio, RFPs have been issued in order to satisfy the need for additional capacity resources. The table below includes RFPs recently issued for both owned and purchased power generation. Unless otherwise noted, RFPs issued are all-source solicitations for accredited capacity with consideration made for renewable projects. Projects selected will be subject to regulatory approval.

Company	Issuance Date	Projected In-Service Dates	Generating Capacity
			(in MWs)
I&M (a)	March 2023	Year End 2027	2,505
APCo (b)	April 2023	Year End 2026	800
KPCo (c)	September 2023	Year End 2026/2027	1,300
PSO	November 2023	Year End 2027/2028	1,500
SWEPCo	January 2024	Year End 2028	2,100
Total Significant RFPs			8,205

(a) RFP is seeking nameplate capacity proposals from various types of generation. Actual MWs by technology type depends on the portfolio of projects selected and individual contribution toward meeting I&M's overall capacity need.

(b) RFP is seeking nameplate capacity proposals for up to 600 MWs of owned wind or solar and 200 MWs of wind or solar PPAs. Also includes an option for battery storage.

(c) RFP is seeking proposals for PPAs only.

Regulatory Matters - Utility Rates and Rate Proceedings

The Registrants are involved in rate cases and other proceedings 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. Depending on the outcomes, these rate cases and 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.

The following tables show the Registrants' completed and pending base rate case proceedings in 2023. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Annual Base Revenue Increase		Approved ROE	New Rates Effective
		(in millions)			
SWEPCo	Louisiana	$ 21.0	(a)	9.5%	February 2023
PSO	Oklahoma	131.0		9.3%	January 2024
APCo	Virginia	127.0		9.5%	January 2024
KPCo	Kentucky	60.0		9.75%	January 2024

(a) See "2020 Louisiana Base Rate Case" section of Note 4 for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Annual Base Revenue Increase Request	Requested ROE
			(in millions)	
I&M	Indiana	August 2023	$ 116.0	10.5%
I&M	Michigan	September 2023	34.0	10.5%
PSO	Oklahoma	January 2024	218.0	10.8%

Other Significant Regulatory Matters

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. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment 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. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCT. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was remanded to the PUCT for future proceedings. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

On December 14, 2023, the PUCT approved a preliminary order stating the PUCT will not address SWEPCo's request that would allow the PUCT to find cause to allow SWEPCo to exceed the Texas jurisdictional capital cost cap in the current remand proceeding. As a result of the PUCT's approval of the preliminary order, SWEPCo believes it is probable the PUCT will disallow capitalized AFUDC in excess of the Texas jurisdictional capital cost cap and recorded a pretax, non-cash disallowance of $86 million in the fourth quarter of 2023. Such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis. On December 21, 2023, SWEPCo filed a motion with the PUCT for reconsideration of the preliminary order. In January 2024, the PUCT denied the motion for reconsideration of the preliminary order.

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. In January 2024, the PUCT established a procedural schedule for the remand proceeding. Supplemental testimony from SWEPCo is due in March 2024, intervenor and staff testimony is due in April 2024 and a hearing is scheduled for May 2024. Although SWEPCo does not currently believe any refunds are probable of occurring, SWEPCo estimates it could be required to make customer refunds, including interest, ranging from $0 to $200 million related to revenues collected from February 2013 through December 2023.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

The Registrants transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2023, 2022 and 2021 by $60 million, $69 million and $78 million, respectively.

In March 2023 and May 2023, certain joint customers submitted a complaint and a formal challenge at the FERC related to the 2022 Annual Update of the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP, respectively. These challenges primarily relate to stand-alone treatment of NOLCs in the transmission formula rates of the AEP transmission owning subsidiaries. AEPSC, on behalf of the AEP transmission owning subsidiaries within PJM and SPP, filed answers to the joint formal challenge and complaint with the FERC in the second quarter of 2023.

In January 2024, the FERC issued two orders, granting the joint customers' challenges related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests with the FERC that it grant rehearing and reverse findings in its January 2024 orders or establish hearing procedures to address outstanding factual issues.

As a result of the January 2024 FERC orders, the Registrants' 2022 and 2023 income statements cumulatively reflect a provision for refund for the probable refund of all NOLC revenues included in transmission formula rates for years 2023, 2022 and 2021. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms. The FERC directed cash refunds with interest related to the 2021 rate year to occur through the annual update for the next rate year, which will be invoiced by PJM and SPP primarily in 2025. The Registrants have not yet been directed to make cash refunds related to the 2022 or 2023 rate years.

The FERC's January 2024 orders reduced AEP and AEPTCo's 2023 pretax net income by approximately $76 million and $74 million, respectively. The impact of the FERC's orders on the pretax net income of AEP's remaining Registrant Subsidiaries was not material.

Kentucky Securitization Case

In conjunction with KPCo’s June 2023 base rate case filing, KPCo requested to finance, through the issuance of securitization bonds, approximately $471 million of regulatory assets recorded as of June 2023 including: (a) $289 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $52 million of deferred purchased power expenses and (d) $51 million of under-recovered purchased power rider costs.

In January 2024, the KPSC issued a financing order approving KPCo’s securitization request and concluding that costs requested for recovery were prudently incurred. The KPSC’s financing order includes certain additional requirements related to securitization bond structuring, marketing, placement, and issuance that were not reflected in KPCo’s proposal. As a result, in January 2024, KPCo filed a request for rehearing with the KPSC to clarify certain aspects of these additional requirements. In February 2024, the KPSC denied KPCo’s rehearing requests. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the second half of 2024, subject to market conditions. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Deferred Fuel Costs

Increases in fuel and purchased power costs in excess of amounts included in fuel-related revenues has led to an increase in the under collection of fuel costs from customers in several jurisdictions in recent years. To help ease the burden on customers, certain state commissions have issued orders allowing recovery of these costs over periods exceeding the traditional jurisdictional FAC terms. The table below illustrates the current and noncurrent under-recovered fuel regulatory asset balances, by jurisdiction, impacted by these orders. If any of these deferred fuel costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. See Note 4 - Rate Matters and Note 5 - Effects of Regulation for additional information.

Company	Jurisdiction	Expected/Authorized Recovery Period	As of December 31, 2023		As of December 31, 2022	Increase/ (Decrease)
					(in millions)	
APCo	Virginia	2025	$ 254.4	(a)	$ 407.9	$ (153.5)
APCo	West Virginia	2034	162.2	(b)	288.5	(126.3)
PSO	Oklahoma	2024	118.3	(c)	431.5	(313.2)
SWEPCo	Texas	2035	80.9	(d)	80.7	0.2
WPCo	West Virginia	2034	181.3	(b)	231.1	(49.8)
		Total	$ 797.1		$ 1,439.7	$ (642.6)

(a) In September 2023, APCo submitted a filing with the Virginia SCC requesting to extend the previously authorized recovery period through October 2024 to October 2025. Interim Virginia FAC rates were implemented in November 2023. An order from the Virginia SCC is expected in the first quarter of 2024.

(b) In January 2024, the WVPSC issued a final order which resulted in a December 2023 write-off of $222 million ($127 million attributable to APCo and $95 million attributable to WPCo) of under-recovered ENEC regulatory assets as of February 28, 2023. The order approved the recovery of $321 million ($174 million attributable to APCo and $147 million attributable to WPCo) of under-recovered ENEC regulatory assets as of February 28, 2023 over 10 years beginning September 1, 2024. The recovery of the remaining under-recovered ENEC regulatory assets as of December 31, 2023 will be addressed in APCo and WPCo’s 2024 ENEC filing. In February 2024, the Companies filed briefs with the West Virginia Supreme Court to initiate an appeal of this order.

(c) In September 2022, the Director of the Public Utility Division of the OCC approved a Fuel Cost Adjustment rate designed to collect a $402 million deferred fuel balance through December 2024. PSO’s fuel and purchased power expenses are subject to an annual prudency review by the OCC.

(d) In September 2023, the PUCT issued an order approving an unopposed settlement agreement that provides recovery of $81 million of Oxbow mine and Sabine related fuel costs through 2035.

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW (650 MW net maximum capacity) pulverized coal ultra-supercritical generating unit in Arkansas, which was placed in-service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MWs/477 MWs) of the Turk Plant and operates the facility.

Approximately 20% of SWEPCo's portion of the Turk Plant output is currently not subject to cost-based rate recovery in Arkansas. This portion of the plant's output is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under retail cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-approved rates. In November 2022, SWEPCo filed a Certificate of Public Convenience and Necessity with the APSC for approval to operate the Turk plant to serve Arkansas customers and recover the associated costs through a cost recovery rider. Cost-based recovery of the Turk Plant would aid SWEPCo's near-term capacity needs and support compliance with SPP's 2023 increased capacity planning reserve margin requirements. In April 2023, intervenors filed testimony recommending the APSC deny the Certificate of Public Convenience and Necessity on the basis that the Turk Plant is not the least cost alternative. In June 2023, SWEPCo filed rebuttal testimony with the APSC. In July 2023, additional intervenor testimony was filed with the APSC by the Attorney General of Arkansas and the APSC staff with recommendations consistent with the previously filed April 2023 intervenor testimony. A hearing was held in October 2023 and an order is expected in the first quarter of 2024. As of December 31, 2023, the net book value of the Turk Plant was $1.4 billion, before cost of removal including CWIP and inventory. If SWEPCo cannot ultimately recover its investment and expenses related to the Arkansas retail portion of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

Litigation Related to Ohio House Bill 6 (HB 6)

In July 2019, 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 terminated energy efficiency programs as of December 31, 2020, including OPCo's shared savings revenues of $26 million annually and phased out renewable mandates after 2026. HB 6 also provided for continued recovery of existing renewable energy contracts on a bypassable basis through 2032 and included a provision for continued recovery of OVEC costs through 2030 which is allocated to all electric distribution utility customers in Ohio 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 had previously plead guilty and, in March 2023, a federal jury convicted Larry Householder and another individual of participating in the racketeering conspiracy. In 2021, four AEP shareholders filed derivative actions purporting to assert claims on behalf of AEP against certain AEP officers and directors. 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, repealed 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 in May 2021 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 the law changes or 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 derivative actions, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies for additional information.

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, AEP, with assistance from outside advisors, conducted a review of the circumstances surrounding the passage of the bill. Management does 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 U. S. District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. In December 2021, the district court issued an opinion and order dismissing the securities litigation complaint with prejudice, determining that the complaint failed to plead any actionable misrepresentations or omissions. The plaintiffs did not appeal the ruling.

In January 2021, an AEP shareholder filed a derivative action in the U.S. 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 court entered a scheduling order in the New York state court derivative action staying the case other than with respect to briefing the motion to dismiss. AEP filed substantive and forum-based motions to dismiss in April 2022. In June 2022, the Ohio state court entered an order continuing the stays of that case until the final resolution of the consolidated derivative actions pending in Ohio federal district court. In September 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiff subsequently filed a notice of appeal with the New York appellate court. In January 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York. The two derivative actions pending in federal district court in Ohio have been consolidated and the plaintiffs in the consolidated action filed an amended complaint. AEP filed a motion to dismiss the amended complaint and subsequently filed a brief in opposition to the New York plaintiffs' motion to intervene in the consolidated action in Ohio. In March 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. In April 2023, one of the plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Sixth Circuit of the Ohio federal district court order dismissing the consolidated action and denying the intervention. The defendants will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In March 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter was directed to the Board of Directors of AEP (AEP Board) and contained factual allegations involving HB 6 that were generally consistent with those in the derivative litigation filed in state and federal court. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect. In April 2023, AEP received a litigation demand from counsel representing the purported AEP shareholder who filed the dismissed derivative action in New York state court and unsuccessfully tried to intervene in the consolidated derivative actions in Ohio federal court. The litigation demand letter is directed to the AEP Board 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 certain current and former directors and officers, and that AEP commence a civil action for breaches of fiduciary duty and related claims against any individuals who allegedly harmed AEP. The AEP Board considered the 2023 litigation demand letter and formed a committee of the Board (the "Demand Review Committee") to investigate, review, monitor and analyze the allegations in the letter and make a recommendation to the AEP Board regarding a reasonable and appropriate response to the same. 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 passage of HB 6 and documents relating to AEP's policies and financial processes and controls. In August 2022, AEP received a second subpoena from the SEC seeking various additional documents relating to its ongoing investigation. AEP is cooperating fully with the SEC's investigation, which has included taking testimony from certain individuals and inquiries regarding Empowering Ohio's Economy, Inc., which is a 501(c)(4) social welfare organization, and related disclosures. The SEC staff has advanced its discussions with certain parties involved in the investigation, including AEP, concerning the staff's intentions regarding potential claims under the securities laws. AEP and the SEC are engaged in discussions about a possible resolution of the SEC's investigation and potential claims under the securities laws. Any resolution or filed claims, the outcome of which cannot be predicted, may subject AEP to civil penalties and other remedial measures. Discussions are continuing and management is unable to determine a range of potential losses that is reasonably possible of occurring, but management does not believe the results of this investigation or a possible resolution thereof will have a material impact on results of operations, cash flows or financial condition.

Claims for Indemnification Made by Owners of the Gavin Power Station

In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow a CCR surface impoundment at the Gavin Power Station to continue to receive CCR and non-CCR waste streams after April 11, 2021 until May 4, 2023 (the Gavin Denial). As part of the Gavin Denial, the Federal EPA made several assertions related to the CCR Rule (see "CCR Rule" section below for additional information), including an assertion that the closure of the 300 acre unlined fly ash reservoir (FAR) is noncompliant with the CCR Rule in multiple respects. The Gavin Power Station was formerly owned and operated by AEP and was sold to Gavin Power LLC and Lightstone Generation LLC in 2017. Pursuant to the PSA, AEP maintained responsibility to complete closure of the FAR in accordance with the closure plan approved by the Ohio EPA which was completed in July 2021. The PSA contains indemnification provisions, pursuant to which the owners of the Gavin Power Station have notified AEP they believe they are entitled to indemnification for any damages that may result from these claims, including any future enforcement or litigation resulting from any determinations of noncompliance by the Federal EPA with various aspects of the CCR Rule consistent with the Gavin Denial. The owners of the Gavin Power Station have also sought indemnification for landowner claims for property damage allegedly caused by modifications to the FAR. Management does not believe that the owners of the Gavin Power Station have any valid claim for indemnity or otherwise against AEP under the PSA. In addition, Gavin Power LLC, several AEP subsidiaries, and other parties have filed Petitions for Review of the Gavin Denial with the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to determine a range of potential losses that is reasonably possible of occurring. Gavin Power LLC has also filed a complaint with the United States District Court for the Southern District of Ohio, alleging various violations of the Administrative Procedure Act and asserting that the Federal EPA, through its prior inaction, has waived and is estopped from raising certain objections raised in the Gavin Denial. Management cannot predict the outcome of that litigation.

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.

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's operations. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2023, AEP owned generating capacity of approximately 23,300 MWs, of which approximately 10,700 MWs were coal-fired. Management continues to evaluate the economic feasibility of environmental investments on AEP's fossil generation fleet and to refine the cost estimates of complying with these rules and evaluate other impacts of the environmental proposals on fossil generation.

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, (g) compliance with the Federal EPA's revised coal combustion residual rules and (h) other factors.

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 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 CAA. Revisions 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. In February 2024, the Federal EPA finalized a new more stringent annual primary PM2.5 standard.

Areas with air quality that does not meet the new standard will be designated by the Federal EPA as "nonattainment," which will trigger an obligation for states to revise their SIPs to obtain further emission reductions to ensure that the new standard will be met. Areas around some of AEP's generating facilities may be deemed nonattainment, which may subject those facilities to additional pollution controls or operational constraints. The nonattainment designations by the Federal EPA and the subsequent SIP revisions by the affected states will take some time to complete, therefore, it is too soon to predict how SIP requirements may impact AEP's operations. Management will continue to monitor the issue.

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. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

In 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 Circuit. Management 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 that the Federal EPA began implementing in 2015, which was designed to address interstate transport of emissions that contribute significantly to non-attainment and interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 PM NAAQS in downwind states. 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 basis. The Federal EPA has revised, or updated, the CSAPR trading programs several times since they were established.

In January 2021, the Federal EPA finalized a revised CSAPR, which substantially reduced the ozone season NO_X budgets for several states, including states where AEP operates, beginning in ozone season 2021. 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.

In addition, in February 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states addressing the 2015 Ozone NAAQS. Disapproval of the SIPs provides the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapproved. In August 2023, a FIP went into effect that further revises the ozone season NO_X budgets under the existing CSAPR program in states to which the FIP applies. The disapproval of SIPs and implementation of FIPs continues to be subject to extensive litigation. Management will continue to monitor the outcome of this litigation and any potential impact to operations.

Climate Change, CO_2 Regulation and Energy Policy

In May 2023, the Federal EPA proposed greenhouse gas standards and guidelines for new and existing fossil-fuel fired sources. The proposal relies heavily on carbon capture and sequestration and natural gas co-firing as means to reduce CO_2 emissions from coal fired plants and hydrogen co-firing and carbon capture and sequestration to reduce CO_2 emissions from gas turbines. Management is evaluating the proposed rule.

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.

AEP routinely submits IRPs in various regulatory jurisdictions to address future generation and capacity needs. These IRPs take into account economics, customer demand, grid reliability and resilience, regulations and RTO capacity requirements. The objective of the IRPs is to recommend future generation and capacity resources that provide the most cost-efficient and reliable power to customers. Based on the output of the company's IRPs, in October 2022, AEP announced new intermediate and long-term CO_2 emission reduction goals. AEP adjusted its near-term CO_2 emission reduction target from a 2000 baseline to a 2005 baseline, upgraded its 80% reduction by 2030 target to include full Scope 1 emissions and accelerated its net-zero goal by five years to 2045 for Scope 1 and Scope 2 emissions. AEP's total Scope 1 GHG estimated emissions in 2023 were approximately 42.8 million metric tons, a 68% reduction according to the GHG Protocol, which excludes emission reductions that result from assets that have been sold, or a 72% reduction from AEP's 2005 Scope 1 GHG emissions (inclusive of emission reductions that result from plants that have been sold).

AEP has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline over the long-term. AEP also expects Scope 1 GHG emissions to vary annually depending on the mix of its own generation and purchased power used to serve customers. AEP's ability to achieve these goals is dependent upon a number of factors including the ability to execute on renewable resource plans, evolving RTO requirements, constructive regulatory support, the advancement of carbon-free generation technologies, customer demand for carbon-free energy, potential tariffs, carbon policy and regulation, operational performance of renewable generation and supply chain costs and constraints, all while continuing to provide the most cost-efficient and reliable power to 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.

MATS Rule

In April 2023, the Federal EPA issued a proposed rule that would revise the MATS for power plants. The proposed rule includes a more stringent standard for emissions of filterable PM for coal-fired electric generating units, as well as a new mercury standard for lignite-fired electric generating units. The proposed rule also requires the installation and operation of continuous emissions monitors for PM. Management is evaluating the impacts of the rule as proposed and will continue to monitor the rulemaking.

CCR 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 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 requires 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 various plants.

In January 2022, the Federal EPA proposed to deny several extension requests filed by the other utilities based on allegations that those utilities are not in compliance with the CCR Rule (the January Actions). In November 2022, the Federal EPA finalized one of these denials (the Gavin Denial, discussed above). The Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements. The January Actions of the Federal EPA and the Gavin Denial have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit as unlawful rulemaking that revises the existing CCR Rule requirements without proper notice and without opportunity for comment. Management is unable to predict the outcome of that litigation or how it may impact the Federal EPA's interpretation of the CCR Rule.

In July 2022, the Federal EPA proposed conditional approval of the pending extension request for APCo's Mountaineer Plant. The Federal EPA alleged that the Mountaineer Plant was not fully compliant with the CCR Rule. In December 2022, AEP withdrew the pending extension request for the Mountaineer Plant as work to construct new CCR disposal facilities was completed and the extension was no longer needed. In addition, AEP ceased receiving ash in the other ponds subject to the extension requests, completed construction of new, CCR Rule compliant facilities and withdrew all of the remaining applications for additional time to develop alternative disposal capacity.

Under the second option for obtaining an extension of the April 11, 2021 deadline to cease operation of unlined impoundments, a generating facility may continue operating its existing impoundments without developing alternative CCR disposal, provided the facility commits to cease combustion of coal by a date certain. Under this option, a generating facility had until October 17, 2023 to cease coal-fired operations 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 Plant and cease using coal at the Welsh Plant. In March 2023, the Pirkey Plant was retired. To date, the Federal EPA has not taken any action on the pending extension request for the Welsh Plant.

Closure and post-closure estimated costs have been included in ARO in accordance with the requirements in the Federal EPA's final CCR 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. AEP may incur significant additional costs complying with the Federal EPA's CCR Rule, including costs to upgrade or close and replace surface impoundments and landfills used to manage CCR and to conduct any required remedial actions including removal of coal ash. If additional costs are incurred and AEP is unable to obtain cost recovery, it would reduce future net income and cash flows and impact financial condition. Management will continue to participate in rulemaking activities and make adjustments based on new federal and state requirements affecting its ash disposal units.

In May 2023, the Federal EPA proposed revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units"). The Federal EPA is proposing that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The proposal establishes accelerated compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within one year after the effective date of the final rule. The Federal EPA's proposal would require evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. If finalized, AEP may incur material, additional costs complying with the Federal EPA's proposal, including costs to upgrade or close and replace legacy CCR surface impoundments and to conduct any required remedial actions including removal of coal ash. In addition, AEP would need to seek cost recovery through regulated rates, including proposing new regulatory mechanisms for cost recovery, for which regulatory approval cannot be assured. The proposed rule, if finalized, could have a material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover any additional costs of compliance.

Clean Water Act Regulations

The Federal EPA's ELG rule for generating facilities establishes limits for 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 revision to the ELG rule, published in October 2020, established additional options for reusing and discharging small volumes of bottom ash transport water, provided an exception for retiring units and extended 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 actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. For affected facilities that must install additional technologies to meet the ELG rule limits, permit modifications were filed in January 2021 that reflect the outcome of that assessment. AEP continues to work with state agencies to finalize permit terms and conditions. Other facilities opted to file Notices of Planned Participation (NOPP), pursuant to which the facilities are not required to install additional controls to meet ELG limits provided they make commitments to cease coal combustion by a date certain. In March 2023, the Federal EPA proposed further revisions to the ELG rule which, if finalized, would establish a zero discharge standard for FGD wastewater and bottom ash transport water, and more stringent discharge limits for combustion residual leachate. Management is evaluating the impacts of the proposed rule to operations. Management cannot predict whether the Federal EPA will actually finalize further revisions, but will continue to monitor this issue and will participate in further rulemaking activities as they arise.

The definition of "waters of the United States" has been subject to rule making and litigation which has led to inconsistent scope among the states. Management will continue to monitor developments in rule making and litigation for any potential impact to operations.

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, remediation 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.

The table below summarizes the net book value, as of December 31, 2023, of generating facilities retired or planned for early retirement in advance of the retirement date currently authorized for ratemaking purposes:

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	$ 104.5	$ 164.2	2026	(c)	$ 15.0
SWEPCo	Pirkey Plant	—	114.4 (d)	2023	(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	352.0	125.6	2028 (f)	(g)	38.6

(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) Represents Arkansas and Texas jurisdictional share.
(e) As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. The Texas share of the Pirkey Plant will be addressed in SWEPCo's next base rate case. See the "Coal-Fired Generation Plants" section of Note 5 for additional information.
(f) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028. Management is evaluating a potential conversion to natural gas after 2028 for both units.
(g) 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.

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 is not deemed recoverable, it could materially reduce future net income, cash flows and impact financial condition.

RESULTS OF OPERATIONS

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 are as follows:

- Vertically Integrated Utilities
- Transmission and Distribution Utilities
- AEP Transmission Holdco
- Generation & Marketing

The remainder of AEP's activities are presented as Corporate and Other, which is not considered a reportable segment. See Note 9 - Business Segments for additional information on AEP's segments.

The following discussion of AEP's results of operations by operating segment provides a comparison of Earnings Attributable to AEP Common Shareholders for the year ended December 31, 2023 as compared to the year ended December 31, 2022. For AEP's Vertically Integrated Utilities and Transmission and Distribution Utilities segment and subsidiary registrants within these segments, the results include revenues from rate rider mechanisms designed to recover fuel, purchased power and other recoverable expenses such that the revenues and expenses associated with these items generally offset and do not affect Earnings Attributable to AEP Common Shareholders. For additional information regarding the financial results for the years ended December 31, 2023 and 2022 see the discussions of Results of Operations by Subsidiary Registrant.

A detailed discussion of AEP's 2022 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2022 Annual Report on Form 10-K filed with the SEC on February 23, 2023.

The following tables present Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Years Ended December 31,		
	2023	2022	2021
		(in millions)	
Vertically Integrated Utilities	$ 1,090.4	$ 1,292.0	$ 1,113.6
Transmission and Distribution Utilities	698.7	595.7	543.4
AEP Transmission Holdco	702.9	673.5	677.8
Generation & Marketing	(26.3)	283.6	217.5
Corporate and Other	(257.6)	(537.6)	(64.2)
Earnings Attributable to AEP Common Shareholders	$ 2,208.1	$ 2,307.2	$ 2,488.1

Year Ended December 31, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
		(in millions)		
Revenues	$ 11,449.5	$ 5,713.3	$ 1,728.5	$ 1,632.2
Fuel, Purchased Electricity and Other	4,150.3	1,214.8	—	1,487.8
Other Operation and Maintenance	3,211.1	1,947.8	141.6	132.9
Asset Impairments and Other Related Charges	85.6	—	—	—
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	—	—	92.7
Depreciation and Amortization	1,876.4	784.7	402.6	42.7
Taxes Other Than Income Taxes	512.5	668.0	290.1	6.6
Operating Income (Loss)	1,613.6	1,098.0	894.2	(130.5)
Other Income	25.6	2.8	8.9	44.8
Allowance for Equity Funds Used During Construction	46.3	45.5	83.1	—
Non-Service Cost Components of Net Periodic Benefit Cost	126.3	56.2	6.2	26.2
Interest Expense	(764.5)	(363.6)	(202.6)	(76.0)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	1,047.3	838.9	789.8	(135.5)
Income Tax Expense (Benefit)	(45.2)	140.2	166.0	(122.9)
Equity Earnings (Loss) of Unconsolidated Subsidiary	1.4	—	82.9	(16.5)
Net Income (Loss)	1,093.9	698.7	706.7	(29.1)
Net Income (Loss) Attributable to Noncontrolling Interests	3.5	—	3.8	(2.8)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 1,090.4	$ 698.7	$ 702.9	$ (26.3)

Year Ended December 31, 2022

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
		(in millions)		
Revenues	$ 11,477.5	$ 5,512.0	$ 1,677.0	$ 2,466.9
Fuel, Purchased Electricity and Other	4,007.9	1,287.3	—	1,984.3
Other Operation and Maintenance	3,287.2	1,864.2	165.7	118.7
Asset Impairments and Other Related Charges	24.9	—	—	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	—	—
Gain on Sale of Mineral Rights	—	—	—	(116.3)
Depreciation and Amortization	2,007.2	746.7	355.0	93.0
Taxes Other Than Income Taxes	504.9	659.9	277.6	11.1
Operating Income	1,682.4	953.9	878.7	376.1
Other Income	30.2	4.9	2.0	38.9
Allowance for Equity Funds Used During Construction	29.5	33.6	70.6	—
Non-Service Cost Components of Net Periodic Benefit Cost	109.8	47.6	5.0	20.6
Interest Expense	(650.9)	(328.0)	(169.3)	(51.8)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	1,201.0	712.0	787.0	383.8
Income Tax Expense (Benefit)	(93.8)	116.9	193.6	(83.1)
Equity Earnings (Loss) of Unconsolidated Subsidiary	1.4	0.6	83.4	(192.4)
Net Income	1,296.2	595.7	676.8	274.5
Net Income (Loss) Attributable to Noncontrolling Interests	4.2	—	3.3	(9.1)
Earnings Attributable to AEP Common Shareholders	$ 1,292.0	$ 595.7	$ 673.5	$ 283.6

Year Ended December 31, 2021

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
		(in millions)		
Revenues	$ 9,998.5	$ 4,492.9	$ 1,526.2	$ 2,163.7
Fuel, Purchased Electricity and Other	3,144.2	729.9	—	1,806.8
Other Operation and Maintenance	3,043.1	1,573.9	132.3	97.5
Asset Impairments and Other Related Charges	11.6	—	—	—
Depreciation and Amortization	1,747.6	690.3	306.0	80.9
Taxes Other Than Income Taxes	497.3	640.9	245.0	10.5
Operating Income	1,554.7	857.9	842.9	168.0
Other Income	13.5	2.6	0.7	4.2
Allowance for Equity Funds Used During Construction	40.2	32.3	67.2	—
Non-Service Cost Components of Net Periodic Benefit Cost	67.9	29.0	2.1	15.4
Interest Expense	(574.2)	(300.9)	(146.3)	(15.6)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	1,102.1	620.9	766.6	172.0
Income Tax Expense (Benefit)	(11.2)	77.5	159.6	(48.8)
Equity Earnings (Loss) of Unconsolidated Subsidiary	3.4	—	75.0	(10.6)
Net Income	1,116.7	543.4	682.0	210.2
Net Income (Loss) Attributable to Noncontrolling Interests	3.1	—	4.2	(7.3)
Earnings Attributable to AEP Common Shareholders	$ 1,113.6	$ 543.4	$ 677.8	$ 217.5

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2023	2022	2021
	(in millions of KWhs)		
Retail:			
Residential	30,290	32,835	32,149
Commercial	23,481	23,770	22,833
Industrial	34,148	34,532	33,181
Miscellaneous	2,229	2,316	2,214
Total Retail	90,148	93,453	90,377
Wholesale (a)	13,401	16,099	19,025
Total KWhs	103,549	109,552	109,402

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2023	2022	2021
	(in degree days)		
Eastern Region			
Actual – Heating (a)	1,992	2,709	2,438
Normal – Heating (b)	2,719	2,717	2,720
Actual – Cooling (c)	1,003	1,187	1,268
Normal – Cooling (b)	1,119	1,106	1,110
Western Region			
Actual – Heating (a)	1,068	1,523	1,241
Normal – Heating (b)	1,464	1,455	1,461
Actual – Cooling (c)	2,590	2,695	2,370
Normal – Cooling (b)	2,277	2,247	2,246

(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.

Reconciliation of Year Ended December 31, 2022 to Year Ended December 31, 2023
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2022	$	1,292.0
Changes in Revenues:		
Retail Revenues		(12.8)
Off-system Sales		56.7
Transmission Revenues		(51.3)
Other Revenues		(20.6)
Total Change in Revenues		(28.0)
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(142.4)
Other Operation and Maintenance		76.1
Asset Impairments and Other Related Charges		(60.7)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset		(37.0)
Depreciation and Amortization		130.8
Taxes Other Than Income Taxes		(7.6)
Other Income		(4.6)
Allowance for Equity Funds Used During Construction		16.8
Non-Service Cost Components of Net Periodic Pension Cost		16.5
Interest Expense		(113.6)
Total Change in Expenses and Other		(125.7)
Income Tax Benefit		(48.6)
Net Income Attributable to Noncontrolling Interests		0.7
Year Ended December 31, 2023	$	1,090.4

The major components of the decrease in Revenues were as follows:

- **Retail Revenues** decreased $13 million primarily due to the following:
  - A $182 million decrease in weather-related usage primarily in the residential class driven by a 28% decrease in heating degree days and a 7% decrease in cooling degree days.
  - An $80 million decrease in fuel revenues primarily due to decreases at I&M, SWEPCo and KPCo, partially offset by increases at APCo and PSO.
  - A $54 million decrease in rider revenues at I&M.

  These decreases were partially offset by:
  - A $71 million increase in base rate revenues at PSO.
  - A $70 million increase at SWEPCo primarily due to base rate revenue increases in Louisiana and Arkansas and rider increases in all retail jurisdictions.
  - A $68 million increase at APCo and WPCo due to rider revenues in Virginia and West Virginia.
  - A $41 million increase in weather-normalized retail margins primarily in the commercial and residential classes.
  - A $34 million increase at APCo due to lower customer refunds related to Tax Reform.
  - A $20 million increase at APCo due to a base rate increase in Virginia implemented in October 2022 following the Virginia Supreme Court remand.
- **Off-system Sales** increased $57 million primarily due to an increase at I&M primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales. This increase was partially offset by decreases at APCo and SWEPCo.
- **Transmission Revenues** decreased $51 million primarily due to the following:
  - A $33 million decrease in transmission formula rate true-up activity.
  - A $13 million decrease due to a FERC order which denied stand-alone treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $21 million primarily due to a decrease in pole attachment revenue at APCo and WPCo.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $142 million primarily due to increases at APCo, PSO and WPCo, partially offset by decreases at I&M, SWEPCo and KPCo. The increase at APCo and WPCo includes the disallowance of under-recovered ENEC regulatory assets in West Virginia.
- **Other Operation and Maintenance** expenses decreased $76 million primarily due to the following:
  - A $76 million decrease in transmission services.
  - A $67 million decrease in employee-related expenses.
  - A $40 million decrease due to a charitable contribution to the AEP Foundation in 2022.

  These decreases were partially offset by:
  - A $34 million increase in Demand Side Management expenses at I&M.
  - A $33 million increase in accounts receivable factoring expenses as a result of increased interest rates.
  - A $21 million increase at APCo due to the amortization of the regulatory asset established in accordance with the August 2022 Virginia Supreme Court opinion related to under-earnings during the 2017-2019 Triennial Review.
  - A $20 million increase due to a FERC order which denied stand-alone treatment of NOLCs in transmission formula rates.
- **Asset Impairments and Other Related Charges** increased $61 million primarily due to the following:
  - An $86 million increase at SWEPCo due to the probable disallowance of Turk Plant capitalized AFUDC in excess of the Texas jurisdictional capital cost cap as a result of the PUCT's December 2023 preliminary order in the 2012 Texas Base Rate Case.

  This increase was partially offset by:
  - A $25 million decrease at APCo due to a prior year write-off of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to the 2017-2019 Virginia Triennial Review.
- **Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset** decreased $37 million at APCo due to a prior year establishment of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to under-earning during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses decreased $131 million primarily due to a $170 million decrease at AEGCo and I&M due to the expiration of the Rockport Plant, Unit 2 lease in December 2022, partially offset by an increase in depreciation expense due to the acquisition of Rockport Plant, Unit 2 at the end of the lease.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to the following:
  - A $15 million increase at PSO and SWEPCo primarily due to increased property taxes driven by the investment in NCWF.
  - A $5 million increase at APCo primarily due to an increase in Virginia state minimum taxes.

  These increases were partially offset by:
  - A $13 million decrease at I&M primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to higher AFUDC equity rates and CWIP at PSO and SWEPCo.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $17 million primarily due to the change in loss amortization for the plans and an increase in the expected return on asset assumption, partially offset by higher interest costs due to increased discount rates.
- **Interest Expense** increased $114 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Benefit** decreased $49 million primarily due to the following:
  - A $29 million increase in state taxes.
  - A $27 million decrease due to a decrease in amortization of Excess ADIT.
  - A $19 million decrease related to tax return to provision adjustments.

  These decreases were partially offset by:
  - A $27 million increase due to PTCs.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2023	2022	2021
	(in millions of KWhs)		
Retail:			
Residential	26,099	27,479	26,830
Commercial	30,419	27,448	25,514
Industrial	26,571	25,435	23,919
Miscellaneous	745	753	737
Total Retail (a)	83,834	81,115	77,000
Wholesale (b)	1,922	2,198	2,018
Total KWhs	85,756	83,313	79,018

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

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

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

	Years Ended December 31,		
	2023	2022	2021
	(in degree days)		
Eastern Region			
Actual – Heating (a)	2,380	3,116	2,815
Normal – Heating (b)	3,185	3,185	3,190
Actual – Cooling (c)	842	1,121	1,222
Normal – Cooling (b)	1,026	1,011	1,016
Western Region			
Actual – Heating (a)	197	450	341
Normal – Heating (b)	318	312	310
Actual – Cooling (d)	3,208	2,984	2,653
Normal – Cooling (b)	2,737	2,714	2,712

(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.

Reconciliation of Year Ended December 31, 2022 to Year Ended December 31, 2023
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2022	$	595.7
Changes in Revenues:		
Retail Revenues		186.2
Off-system Sales		(86.4)
Transmission Revenues		56.6
Other Revenues		44.9
Total Change in Revenues		201.3
Changes in Expenses and Other:		
Purchased Electricity for Resale		149.4
Purchased Electricity from AEP Affiliates		(77.0)
Other Operation and Maintenance		(83.6)
Depreciation and Amortization		(38.0)
Taxes Other Than Income Taxes		(8.1)
Other Income		(2.1)
Allowance for Equity Funds Used During Construction		11.9
Non-Service Cost Components of Net Periodic Benefit Cost		8.6
Interest Expense		(35.6)
Total Change in Expenses and Other		(74.5)
Income Tax Expense		(23.3)
Equity Earnings of Unconsolidated Subsidiaries		(0.6)
Year Ended December 31, 2023	$	698.6

The major components of the increase in Revenues were as follows:

- **Retail Revenues** increased $186 million primarily due to the following:
  - A $225 million increase in Ohio rider revenues.
  - A $25 million increase in interim rates driven by increased distribution investment in Texas.

  These increases were partially offset by:
  - A $59 million decrease in weather-related usage primarily due to a 28% decrease in heating degree days.
  - A $13 million decrease in weather-normalized revenues in all retail classes in Texas.
  - A $7 million decrease in revenue from rate riders in Texas.
- **Off-system Sales** decreased $86 million primarily due to decreased sales at OVEC driven by lower market prices and volume.
- **Transmission Revenues** increased $57 million primarily due to the following:
  - A $28 million increase in load in Texas.
  - A $27 million increase in interim rates primarily due to transmission investments in Texas.
- **Other Revenues** increased $45 million primarily due to refundable sales of renewable energy credits in Ohio.

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

- **Purchased Electricity for Resale** expenses decreased $149 million primarily due to the following:
  - A $129 million increase in deferrals of OVEC costs.
  - A $69 million decrease in auction volumes primarily due to decreased load, partially offset by higher prices in Ohio.

  These decreases were partially offset by:
  - A $36 million increase in recoverable expenses due to creation, consumption and liquidation of renewable energy credits and recoverable renewable energy purchase agreement expenses.
- **Purchased Electricity from AEP Affiliates** expenses increased $77 million due to increased affiliated auction volumes driven by AEP Energy auctions won in June 2023 in Ohio.

- **Other Operation and Maintenance** expenses increased $84 million primarily due to the following:
  - A $96 million increase due to an energy assistance program for qualified Ohio customers.
  - A $34 million increase in transmission expenses due to an increase in recoverable PJM expenses driven by additional transmission investment.
  - A $23 million increase in recoverable distribution expenses primarily related to vegetation management in Ohio.
  - A $13 million increase in distribution-related expenses in Texas.

  These increases were partially offset by:
  - A $32 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered in Texas.
  - A $22 million decrease in employee-related expenses.
  - An $18 million decrease due to a charitable contribution to the AEP Foundation in 2022.
  - An $11 million decrease in recoverable transmission expenses in Texas.
- **Depreciation and Amortization** expenses increased $38 million primarily due to a higher depreciable base, partially offset by a decrease in recoverable rider depreciable expenses in Ohio.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to an increase in Ohio in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** increased $12 million due to a higher AFUDC base.
- **Non-Service Cost Components of Net Period Benefit Cost** decreased $9 million primarily due to the change in loss amortization for the plans and an increase in the expected return on asset assumption, partially offset by higher interest costs due to increased discount rates.
- **Interest Expense** increased $36 million primarily due to a $58 million increase related to higher debt balances and interest rates, partially offset by a $19 million decrease related to higher AFUDC base and rates.
- **Income Tax Expense** increased $23 million primarily due to an increase in pretax book income.

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2023	December 31, 2022
	(in millions)	
Plant in Service	$ 14,630.2	$ 13,217.3
Construction Work in Progress	1,733.8	1,667.5
Accumulated Depreciation and Amortization	1,332.8	1,062.5
Total Transmission Property, Net	$ 15,031.2	$ 13,822.3

Reconciliation of Year Ended December 31, 2022 to Year Ended December 31, 2023
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2022	$ 673.5
Changes in Transmission Revenues:	
Transmission Revenues	51.5
Total Change in Transmission Revenues	51.5
Changes in Expenses and Other:	
Other Operation and Maintenance	24.1
Depreciation and Amortization	(47.6)
Taxes Other Than Income Taxes	(12.5)
Interest and Investment Income	6.9
Allowance for Equity Funds Used During Construction	12.5
Non-Service Cost Components of Net Periodic Pension Cost	1.2
Interest Expense	(33.3)
Total Change in Expenses and Other	(48.7)
Income Tax Expense	27.6
Equity Earnings of Unconsolidated Subsidiary	(0.5)
Net Income Attributable to Noncontrolling Interests	(0.5)
Year Ended December 31, 2023	$ 702.9

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

- **Transmission Revenues** increased $52 million primarily due to a $172 million increase driven by continued investment in transmission assets, partially offset by a $120 million decrease due to a FERC order which denied stand-alone treatment of NOLCs in transmission formula rates.

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

- **Other Operation and Maintenance** expenses decreased $24 million primarily due to the following:
  - A $13 million decrease in employee-related expenses.
  - An $11 million decrease due to a charitable contribution to the AEP Foundation in 2022.
- **Depreciation and Amortization** expenses increased $48 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $13 million primarily due to higher property taxes as a result of increased transmission investments, partially offset by lower property tax rates.
- **Interest and Investment Income** increased $7 million primarily due to higher advances to affiliates and interest rates.
- **Allowance for Equity Funds Used During Construction** increased $13 million primarily due to higher CWIP balances throughout 2023.
- **Interest Expense** increased $33 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** decreased $28 million primarily due to a decrease in state taxes primarily driven by tax adjustments and deferred state tax remeasurements.

GENERATION & MARKETING

Reconciliation of Year Ended December 31, 2022 to Year Ended December 31, 2023
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2022	$	283.6
Changes in Revenues:		
Merchant Generation		(162.9)
Renewable Generation		(55.3)
Retail, Trading and Marketing		(616.5)
Total Change in Revenues		(834.7)
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		496.5
Other Operation and Maintenance		(14.2)
Loss on the Sale of the Competitive Contracted Renewables Portfolio		(92.7)
Gain on Sale of Mineral Rights		(116.3)
Depreciation and Amortization		50.3
Taxes Other Than Income Taxes		4.5
Interest and Investment Income		5.9
Non-Service Cost Components of Net Periodic Benefit Cost		5.6
Interest Expense		(24.2)
Total Change in Expenses and Other		315.4
Income Tax Benefit		39.8
Equity Earnings of Unconsolidated Subsidiaries		175.9
Net Loss Attributable to Noncontrolling Interests		(6.3)
Year Ended December 31, 2023	$	(26.3)

The major components of the decrease in Revenues were as follows:

- **Merchant Generation** decreased $163 million primarily due to lower market prices in 2023.
- **Renewable Generation** decreased $55 million primarily due to the sale of competitive contracted renewables portfolio in August 2023.
- **Retail, Trading and Marketing** decreased $617 million primarily due to a $314 million unrealized loss on economic hedge activity in 2023 and an $87 million unrealized gain on economic hedge activity in 2022 driven by changes in commodity prices.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $497 million primarily due to a reduction in energy costs in 2023.
- **Other Operation and Maintenance** expenses increased $14 million primarily due to a decrease in land sales and a prior year sale of renewable development projects.
- **Loss on the Sale of the Competitive Contracted Renewables Portfolio** increased $93 million due to the pretax loss on the sale in 2023.
- **Gain on Sale of Mineral Rights** decreased $116 million due to the prior year sale of mineral rights.
- **Depreciation and Amortization** expenses decreased $50 million primarily due to the ceasing of depreciation on the competitive contracted renewables portfolio as a result of held for sale classification and subsequent sale in 2023.
- **Interest and Investment Income** increased $6 million primarily due to higher interest rates on advances to affiliates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $6 million primarily due to the elimination of loss amortization for the Qualified plan and an increase in the Qualified expected return on asset assumption from 5.25% for 2022 to 7.50% for 2023.
- **Interest Expense** increased $24 million primarily due to higher interest rates in 2023.

- **Income Tax Benefit** increased $40 million primarily due to:
  - A $74 million increase due to a decrease in pretax book income.

  This increase was partially offset by:
  - A $19 million decrease due to the remeasurement of deferred state taxes.
  - A $9 million decrease due to a decrease in tax credits.
- **Equity Earnings of Unconsolidated Subsidiaries** increased $176 million primarily due to:
  - A $182 million impairment of AEP’s investment in Flat Ridge 2 Wind LLC in 2022.

  This increase was partially offset by:
  - A $19 million impairment of AEP’s investment in New Mexico Renewable Development joint venture in 2023.
- **Net Loss Attributable to Noncontrolling Interests** increased $6 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.

CORPORATE AND OTHER

2023 Compared to 2022

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $538 million in 2022 to a loss of $258 million in 2023 primarily due to:

- A $363 million pretax loss in 2022 related to the anticipated sale of the Kentucky Operations which was terminated in 2023.
- An $81 million increase in interest income, primarily due to higher interest rates on advances to affiliates.
- A $56 million decrease in corporate expenses, primarily due to adjustments driven by the termination of the sale of the Kentucky Operations.
- A $49 million increase in factoring revenues from the affiliates.
- A $30 million increase at EIS, primarily due to higher returns on investments.
- A $24 million increase due to asset impairments and other related charges in 2022.

These increases in earnings were partially offset by:
- A $286 million increase in interest expense due to higher interest rates and an increase in debt balances.
- A $46 million increase in Income Tax Expense primarily due to the following:
    - A $66 million increase due to the loss on the anticipated sale of the Kentucky Operations in 2022.

    This increase was partially offset by:
    - A $15 million decrease due to favorable permanent tax adjustments in the current year and unfavorable permanent tax adjustments in 2022.

AEP CONSOLIDATED INCOME TAXES

2023 Compared to 2022

- **Income Tax Expense** increased $49 million primarily due to the following:
    - A $58 million increase in state tax expense primarily driven by consolidated tax adjustments and deferred state tax remeasurements.
    - A $22 million decrease in amortization of Excess ADIT.
    - A $22 million decrease in PTCs.

    These increases in Income Tax Expense were partially offset by:
    - A $36 million increase in amortization of deferred ITCs resulting from the sale of the competitive contracted renewables portfolio.
    - A $16 million decrease due to favorable permanent tax adjustments in the current year and unfavorable permanent tax adjustments in 2022.

FINANCIAL CONDITION

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

SIGNIFICANT CASH REQUIREMENTS

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. It is anticipated that these obligations will be satisfied through a combination of cash flows from operations, long-term debt issuances, short-term debt through AEP's Commercial Paper Program or bank term loans, proceeds from the sale of competitive contracted renewables and the use of the ATM Program or other equity issuances.

Capital Expenditures

Continued capital investments reflect AEP's commitment to enhance service and deliver reliable, clean energy and advanced technologies that exceed customer expectations. See "Budgeted Capital Expenditures" herein, for additional information.

Long-term Debt

Long-term debt maturities, including interest, represent a significant cash requirement for AEP and the Registrant Subsidiaries. See Note 14 - Financing Activities for additional information relating to the Registrant Subsidiaries' long-term debt outstanding as of December 31, 2023, the weighted-average interest rate applicable to each debt category and a schedule of debt maturities over the next five years.

Other Significant Cash Requirements

Operating and finance leases represent a significant component of funding requirements for AEP and the Registrant Subsidiaries. See Note 13 - Leases for additional information.

AEP subsidiaries have substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. See Note 6 - Commitments, Guarantees and Contingencies for additional information.

As of December 31, 2023, AEP expected to make contributions to the pension plans totaling $7 million in 2024. Estimated contributions of $110 million in 2025 and $6 million in 2026 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 99% funded as of December 31, 2023. See "Estimated Future Benefit Payments and Contributions" section of Note 8 for additional information.

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2023		2022	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 40,143.2	58.8 %	$ 36,801.0	56.6 %
Short-term Debt	2,830.2	4.2	4,112.2	6.3
Total Debt	42,973.4	63.0	40,913.2	62.9
AEP Common Equity	25,246.7	37.0	23,893.4	36.7
Noncontrolling Interests	39.2	—	229.0	0.4
Total Debt and Equity Capitalization	$ 68,259.3	100.0 %	$ 65,035.6	100.0 %

AEP's ratio of debt-to-total capital increased slightly from 62.9% to 63.0% as of December 31, 2022 and December 31, 2023, respectively, primarily due to an increase in Long-term Debt to support distribution, transmission and renewable investment growth in addition to working capital needs. This was partially offset by the issuance of common equity in connection with the settlement of the forward equity purchase contracts related to the 2020 Equity Units and the utilization of cash proceeds received from the sale of the competitive contracted renewables portfolio to reduce Short-term Debt.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of December 31, 2023, AEP had $5 billion in 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. AEP and its utilities finance its operations with commercial paper and other variable rate instruments that are subject to fluctuations in interest rates. To the extent that there is an increase in interest rates, it could reduce future net income and cash flows and impact financial condition.

Market volatility and reduced liquidity in the financial markets could affect AEP's ability to raise capital on reasonable terms to fund capital needs, including construction costs and refinancing maturing indebtedness. AEP is also monitoring the current bank environment and any impacts thereof. AEP was not materially impacted by these conditions during the year ended December 31, 2023.

In August 2023, AEP completed the sale of the entire Competitive Contracted Renewables Portfolio to a nonaffiliated party and received cash proceeds of approximately $1.2 billion, net of taxes and transaction costs. The proceeds were used to pay down debt balances and support AEP's overall capital expenditure plans. See the "Dispositions" section of Note 7 for additional information.

AEP continues to address the cash flow implications of increased fuel and purchased power costs, see "Deferred Fuel Costs" section of Executive Overview for additional information. In January 2024, AEP made a capital contribution to APCo and WPCo, totaling $100 million and $75 million, respectively. These contributions were made to help address the impact of the January 2024 WVPSC order that resulted in the December write-off of $222 million ($127 million attributable to APCo and $95 million attributable to WPCo) of under-recovered ENEC regulatory assets. See "ENEC (Expanded Net Energy Cost) Filings" of Note 4 for additional information.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2023, available liquidity was approximately $3.4 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 4,000.0	March 2027
Revolving Credit Facility	1,000.0	March 2025
Cash and Cash Equivalents	330.1	
Total Liquidity Sources	5,330.1	
Less: AEP Commercial Paper Outstanding	1,937.9	
Net Available Liquidity	$ 3,392.2	

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 2023 was $3.2 billion. The weighted-average interest rate for AEP's commercial paper during 2023 was 5.38%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. As of December 31, 2023, AEP issued letters of credit on behalf of subsidiaries under six uncommitted facilities with a total capacity of $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities, as of December 31, 2023, was $257 million with maturities ranging from January 2024 to November 2024.

Financing Plan

As of December 31, 2023, AEP had $2.5 billion of long-term debt due within one year. This included $510 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current and $205 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the maturities due within one year on a long-term basis.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables. The agreement was amended in August 2023 to increase the commitment from $750 million and expires in September 2025. As of December 31, 2023, the affiliated utility subsidiaries were 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 December 31, 2023, this contractually-defined percentage was 59.9%. 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.

ATM Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, up to an aggregate of $1.7 billion of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. There were no issuances under the ATM program for the year ended December 31, 2023. As of December 31, 2023, approximately $1.7 billion of equity is available for issuance under the ATM offering program. See Note 14 - 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 settled after three years in August 2023. The proceeds were used to support AEP's overall capital expenditure plans.

In June 2023, AEP successfully remarketed the Junior Subordinated Notes on behalf of holders of the corporate units. AEP did not receive any proceeds from the remarketing which were used to purchase a portfolio of treasury securities that matured on August 14, 2023. On August 15, 2023, the proceeds from the treasury portfolio were used to settle the forward equity purchase contract with AEP. The interest rate on the Junior Subordinated Notes was reset to 5.699% with the maturity remaining in 2025. In August 2023, AEP issued 10,048,668 shares of AEP common stock and received proceeds totaling $850 million under the settlement of the forward equity purchase contracts. AEP common stock held in treasury was used to settle the forward equity purchase contracts. The proceeds were used to pay down debt balances and support AEP's overall capital expenditure plans. See Note 14 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.88 per share in January 2024. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 14 for additional information.

Credit Ratings

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

CASH FLOW

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

	Years Ended December 31, 2023	2022	2021
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 556.5	$ 451.4	$ 438.3
Net Cash Flows from Operating Activities	5,012.2	5,288.0	3,839.9
Net Cash Flows Used for Investing Activities	(6,266.7)	(7,751.8)	(6,433.9)
Net Cash Flows from Financing Activities	1,077.0	2,568.9	2,607.1
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(177.5)	105.1	13.1
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 379.0	$ 556.5	$ 451.4

Operating Activities

	Years Ended December 31, 2023	2022	2021
		(in millions)	
Net Income	$ 2,212.6	$ 2,305.6	$ 2,488.1
Non-Cash Adjustments to Net Income (a)	3,394.5	3,461.6	3,025.9
Mark-to-Market of Risk Management Contracts	8.8	15.5	112.3
Property Taxes	(41.1)	(41.2)	(68.0)
Deferred Fuel Over/Under Recovery, Net	892.8	(319.2)	(1,647.9)
Change in Other Noncurrent Assets (b)	(780.9)	(234.4)	(365.5)
Change in Other Noncurrent Liabilities	29.0	337.8	206.4
Change in Certain Components of Working Capital	(703.5)	(237.7)	88.6
Net Cash Flows from Operating Activities	$ 5,012.2	$ 5,288.0	$ 3,839.9

(a) Includes Depreciation and Amortization, Rockport Plant, Unit 2 Lease Amortization, Deferred Income Taxes, Loss on the Expected Sale of the Kentucky Operations, Loss on the Sale of the Competitive Contracted Renewables Portfolio, Asset Impairments and Other Related Charges, Impairment of Equity Method Investment, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel, Gain on Sale of Mineral Rights and Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset.
(b) Includes Change in Regulatory Assets.

2023 Compared to 2022

Net Cash Flows from Operating Activities decreased by $276 million primarily due to the following:

- A $547 million decrease in cash from Change in Other Noncurrent Assets primarily due to incremental other operation and maintenance storm restoration expenses incurred in several jurisdictions in addition to timing differences in collections from customers under rate rider mechanisms. See Note 4 - Rate Matters and Note 5 - Effects of Regulation for additional information.
- A $466 million decrease in cash from the Change in Certain Components of Working Capital. The decrease is primarily due to fuel, material and supplies driven by current year increases in coal inventory, the return of margin deposits from PJM in 2022 and the timing of accounts payable. These decreases were partially offset by the timing of accounts receivable.
- A ### decrease in cash from Changes in Other Noncurrent Liabilities. The decrease is primarily due to changes in provisions for refunds and regulatory liabilities driven by timing differences in refunds to customers under rate rider mechanisms in addition to an increase in ARO settlements in 2023. See Note 5 - Effects of Regulation and Note 18 - Property, Plant and Equipment for additional information.
- A $160 million decrease in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.

These decreases in cash were offset by:

- A ### increase in cash primarily due to the timing of fuel and purchased power revenues and expenses. See the "Deferred Fuel Costs" section of Executive Overview for additional information.

Investing Activities

	Years Ended December 31,		
	2023	2022	2021
		(in millions)	
Construction Expenditures	$ (7,378.3)	$ (6,671.7)	$ (5,659.6)
Acquisitions of Nuclear Fuel	(128.2)	(100.7)	(104.5)
Acquisition of Renewable Energy Facilities	(155.2)	(1,207.3)	(767.2)
Proceeds on Sale of Assets	1,341.4	218.0	118.9
Other	53.6	9.9	(21.5)
Net Cash Flows Used for Investing Activities	$ (6,266.7)	$ (7,751.8)	$ (6,433.9)

2023 Compared to 2022

Net Cash Flows Used for Investing Activities decreased by $1.5 billion primarily due to the following:

- A $1.1 billion decrease due to the 2022 acquisition of Traverse, partially offset by the 2023 acquisition of the Rock Falls Wind Facility. See "Acquisitions" section of Note 7 for additional information.
- A $1.1 billion increase in Proceeds from Sale of Assets, primarily due to the sale of the competitive contracted renewables portfolio in 2023, partially offset by the sale of certain mineral rights in 2022. See "Dispositions" section of Note 7 for additional information.

These decreases in cash used were partially offset by:

- A $707 million increase in Construction Expenditures, primarily due to increases in Vertically Integrated Utilities of $374 million and Transmission and Distribution Utilities of $290 million.

Financing Activities

	Years Ended December 31,		
	2023	2022	2021
		(in millions)	
Issuance of Common Stock	$ 999.6	$ 826.5	$ 600.5
Issuance/Retirement of Debt, Net	1,984.7	3,802.5	3,631.7
Dividends Paid on Common Stock	(1,760.4)	(1,645.2)	(1,519.5)
Principal Payments for Finance Lease Obligations	(68.3)	(309.5)	(64.0)
Other	(78.6)	(105.4)	(41.6)
Net Cash Flows from Financing Activities	$ 1,077.0	$ 2,568.9	$ 2,607.1

2023 Compared to 2022

Net Cash Flows from Financing Activities decreased by $1.5 billion primarily due to the following:

- A $2.8 billion decrease due to changes in short-term debt. See Note 14 - Financing Activities for additional information.
- A $115 million decrease due to an increase in dividends paid on common stock.

These decreases in cash were partially offset by:

- An $813 million increase in issuances of long-term debt. See Note 14 - Financing Activities for additional information.
- A $241 million increase due to a decrease in Principal Payments for Finance Lease Obligations primarily driven by Rockport Plant, Unit 2 final lease payments in 2022.
- A $173 million increase in issuances of common stock primarily due to the settlement of the 2020 equity units. See "Equity Units" section of Note 14 for additional information.
- A $149 million increase due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2023:

AEP Common Stock:

- During 2023, AEP issued 2.3 million shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans. Additionally in 2023, AEP reissued 10 million shares of treasury stock to fulfill share commitments related to AEP's Equity Units. See "Common Stock" and "Equity Units" section of Note 14 for additional information. AEP received net proceeds of $1 billion related to these issuances.

Debt:

- During 2023, AEP issued approximately $5.5 billion of long-term debt, including $5.1 billion of senior unsecured notes at interest rates ranging from 5% to 7%, $296 million of other debt at various interest rates and $125 million of pollution control bonds at interest rates ranging from 4.25% to 4.7%. The proceeds from these issuances were primarily used to fund long-term debt maturities, construction programs and to help address working capital needs.
- During 2023, AEP entered into interest rate derivatives with notional amounts totaling $1.9 billion that were designated as cash flow hedges. During 2023, settlements of AEP's interest rate derivatives resulted in net cash paid of $44 million for derivatives designated as fair value hedges and net cash received of $20 million designated as cash flow hedges. As of December 31, 2023, AEP had a total notional amount of $950 million of outstanding interest rate derivatives designated as fair value hedges and $350 million designated as cash flow hedges.

See "Long-term Debt Subsequent Events" section of Note 14 for Long-term debt and other securities issued, retired and principal payments made after December 31, 2023 through February 26, 2024, the date that the 10-K was issued.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.5 billion of capital expenditures in 2024. For the four year period, 2025 through 2028, management forecasts capital expenditures of $35 billion. The expenditures are generally for transmission, generation, distribution, regulated 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, supply chain issues, weather, legal reviews, inflation and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations, proceeds from the strategic sale of assets and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The estimated capital expenditures by Business Segment are as follows:

	2024 Budgeted Capital Expenditures							2025-2028
Segment	Environmental	Generation	Renewables	Transmission	Distribution	Other (a)	Total	Total
				(in millions)				
Vertically Integrated Utilities	$ 49	$ 367	$ 531	$ 990	$ 1,311	$ 332	$ 3,580	$ 20,407
Transmission and Distribution Utilities	—	—	—	1,272	1,087	208	2,567	9,201
AEP Transmission Holdco	—	—	—	1,313	—	25	1,338	4,902
Generation & Marketing (b)	—	—	—	—	—	—	—	—
Corporate and Other	—	—	—	—	—	59	59	501
Total	$ 49	$ 367	$ 531	$ 3,575	$ 2,398	$ 624	$ 7,544	$ 35,011

(a) Amount primarily consists of facilities, software and telecommunications.
(b) No capital expenditures expected based on the anticipated sale of AEP Energy and AEP Onsite Partners in 2024.

The 2024 estimated capital expenditures by Registrant Subsidiary are as follows:

	2024 Budgeted Capital Expenditures						
Company	Environmental	Generation	Renewables	Transmission	Distribution	Other (a)	Total
				(in millions)			
AEP Texas	$ —	$ —	$ —	$ 897	$ 549	$ 87	$ 1,533
AEPTCo	—	—	—	1,313	—	25	1,338
APCo	22	104	8	324	375	130	963
I&M	—	91	15	76	327	70	579
OPCo	—	—	—	375	538	121	1,034
PSO	—	61	36	133	289	50	569
SWEPCo	3	77	473	349	214	60	1,176

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

Regulatory Accounting

Nature of Estimates Required

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

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

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

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $288 million and $354 million as of December 31, 2023 and 2022, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $(66) million, $108 million and $(42) million for the years ended December 31, 2023, 2022 and 2021, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $191 million and $221 million as of December 31, 2023 and 2022, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $(30) million, $49 million and $1 million for the years ended December 31, 2023, 2022 and 2021, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $111 million and $109 million as of December 31, 2023 and 2022, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $2 million, $(1) million and $24 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Assumptions and Approach Used

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

For AEP's Generation & Marketing segment, management calculates unbilled revenues based on a primary computation of load as provided by PJM less the current month's billed KWhs and estimated line losses, plus the prior month's unbilled KWhs. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon using the most recent historic daily activity on a per contract basis. The two methodologies are evaluated to confirm that they are not statistically different.

Effect if Different Assumptions Used

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

Accounting for Derivative Instruments

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

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

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

Long-Lived Assets

Nature of Estimates Required

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

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

Pension and OPEB

AEPSC maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, non-qualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). AEPSC also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

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

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

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2023**	**2022**	**2021**
		(in millions)	
Pension Plans	$ (24.3)	$ 80.9	$ 138.2
OPEB	(107.1)	(144.8)	(122.0)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2024, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 7.25% for the Qualified Plan and 6.75% for the OPEB plans.

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

	Pension Plans		**OPEB**	
	2024 Target Asset Allocation	**Assumed/Expected Long-Term Rate of Return**	**2024 Target Asset Allocation**	**Assumed/Expected Long-Term Rate of Return**
Equity	30 %	8.77 %	58 %	7.76 %
Fixed Income	54 %	6.02 %	41 %	5.77 %
Other Investments	15 %	9.39 %	—	—
Cash and Cash Equivalents	1 %	3.79 %	1 %	3.79 %
Total	100 %		100 %	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 7.25% for the Qualified Plan and 6.75% for the OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 9.50% and a loss of 16.88% for the years ended December 31, 2023 and 2022, respectively. The OPEB plans' assets had an actual gain of 15.48% and a loss of 19.53% for the years ended December 31, 2023 and 2022, respectively. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2023, AEP had cumulative gains of approximately $526 million for the Qualified Plan that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2023 under this method was 5.15% for the Qualified Plan, 5.2% for the Nonqualified Plans and 5.15% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return, discount rates and various other assumptions, management estimates costs (credits) for the Pension Plans will approximate $(6) million, $39 million and $77 million in 2024, 2025 and 2026, respectively. Based on an expected rate of return discount rate and various other assumptions, management estimates OPEB plan credits will approximate $72 million, $60 million and $66 million in 2024, 2025 and 2026, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets is $4.1 billion as of December 31, 2023 and $4.1 billion as of December 31, 2022. During 2023, the Qualified Plan paid $361 million and the Nonqualified Plans paid $8 million in benefits to plan participants. The value of AEP's OPEB plans' assets increased to $1.7 billion as of December 31, 2023 from $1.5 billion as of December 31, 2022 primarily due to positive investment returns. During 2023, the OPEB plans paid $138 million in benefits to plan participants.

Nature of Estimates Required

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

Assumptions and Approach Used

The critical assumptions used in developing the required estimates includes discount rate, compensation increase rate, cash balance crediting rate, health care cost trend rate and expected return on plan assets. Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

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

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2023 Benefit Obligations				
Discount Rate	$ (177.9)	$ 193.7	$ (36.2)	$ 39.3
Compensation Increase Rate	226.0	(21.1)	NA	NA
Cash Balance Crediting Rate	60.2	(56.9)	NA	NA
Health Care Cost Trend Rate	NA	NA	5.1	(4.4)
Effect on 2023 Periodic Cost				
Discount Rate	$ (9.3)	$ 10.1	$ 1.6	$ (1.7)
Compensation Increase Rate	4.9	(4.5)	NA	NA
Cash Balance Crediting Rate	11.1	(10.5)	NA	NA
Health Care Cost Trend Rate	NA	NA	0.5	(0.3)
Expected Return on Plan Assets	(22.6)	22.6	(7.6)	7.6

NA Not applicable.

SIGNIFICANT TAX LEGISLATION

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022, or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash.

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits. In the third and fourth quarter of 2023, AEP, on behalf of PSO, SWEPCo and AEP Energy Supply, LLC, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $102 million received in the fourth quarter of 2023 and an additional $76 million expected in early 2024. AEP expects to continue to explore the ability to efficiently monetize its tax credits through third party transferability agreements. See Note 12 - Income Taxes for additional information.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards.

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 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 Commercial Officer, Executive Vice President Utilities, Senior Vice President of Regulated Commercial Operations, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Chief Commercial Officer, Senior Vice President of Treasury and Risk, Senior Vice President of Competitive Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2022:

MTM Risk Management Contract Net Assets (Liabilities)

Year Ended December 31, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2022	$ 134.7	$ (40.0)	$ 360.5	$ 455.2
(Gain)/Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(158.8)	2.0	(170.1)	(326.9)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	3.9	3.9
Changes in Fair Value Due to Market Fluctuations During the Period (b)	24.5	—	(101.9)	(77.4)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	16.5	(13.0)	—	3.5
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2023	$ 16.9	$ (51.0)	$ 92.4	$ 58.3
Commodity Cash Flow Hedge Contracts				133.1
Interest Rate Cash Flow Hedge Contracts				(9.0)
Fair Value Hedge Contracts				(98.4)
Collateral Deposits				(16.7)
Total MTM Derivative Contract Net Assets as of December 31, 2023				$ 67.3

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

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

Credit Risk

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

AEP has risk management contracts (includes non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 2023, credit exposure net of collateral to sub investment grade counterparties was approximately 7.2%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of December 31, 2023, 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	$ 395.4	$ 48.7	$ 346.7	2	$ 126.9
Split Rating	25.1	—	25.1	1	25.1
Noninvestment Grade	0.2	0.2	—	—	—
No External Ratings:					
Internal Investment Grade	34.9	—	34.9	4	23.4
Internal Noninvestment Grade	80.4	48.7	31.7	2	27.4
Total as of December 31, 2023	$ 536.0	$ 97.6	$ 438.4		

All exposure in the table above relates to AEPSC and AEPEP as AEPSC is agent for and transacts on behalf of certain 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 December 31, 2023, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities.

The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2023				Twelve Months Ended December 31, 2022			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 0.9	$ 0.2	$ 0.1	$ 0.5	$ 4.5	$ 0.7	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2023				Twelve Months Ended December 31, 2022			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 17.7	$ 32.7	$ 16.4	$ 6.1	$ 17.7	$ 76.9	$ 24.7	$ 6.7

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. Prior to 2022, interest rates remained at low levels and the Federal Reserve maintained the federal funds target range at 0.0% to 0.25% for much of 2021. However, during 2022, the Federal Reserve approved several rate increases for a cumulative total of 4.25% increase. During 2023, the Federal Reserve approved another four rate increases for a cumulative total of 1.0% rate increase. AEP has outstanding short and long-term debt which is subject to variable rates. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the twelve months ended December 31, 2023, 2022 and 2021, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $40 million, $47 million and $33 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the "Company") as of December 31, 2023 and 2022 and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2023, including the related notes and financial statement schedules listed in the index appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

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

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1 and 5 to the consolidated financial statements, the Company's consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. As of December 31, 2023, there were $5.6 billion of deferred costs included in regulatory assets, $0.8 billion of which were pending final regulatory approval, and $8.2 billion of regulatory liabilities awaiting potential refund or future rate reduction, $0.2 billion of which were pending final regulatory determination. Regulatory assets (deferred expenses) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and matching income with its passage to customers in cost-based regulated rates. Management reviews the probability of recovery of regulatory assets and refund of regulatory liabilities at each balance sheet date and whenever new events occur, such as changes in the regulatory environment, issuance of regulatory commission orders, or passage of new legislation.

The principal considerations for our determination that performing procedures relating to the accounting for the effects of cost-based regulation is a critical audit matter are the significant judgment by management in the ongoing evaluation of the recovery of regulatory assets and refund of regulatory liabilities, and in applying guidance contained in rate orders and other relevant evidence; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence related to the probability of recovery of regulatory assets and refund of regulatory liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's evaluation of new events, such as changes in the regulatory environment, issuance of regulatory commission orders, or passage of new legislation, including the probability of recovery of regulatory assets and refund of regulatory liabilities. These procedures also included, among others, evaluating the reasonableness of management's assessment of probability of future recovery for regulatory assets and refund of regulatory liabilities. Testing of regulatory assets and liabilities involved evaluating the provisions and formulas outlined in rate orders, other regulatory correspondence, application of relevant regulatory precedents, and other relevant evidence.

Valuation of Level 3 Risk Management Commodity Contracts

As described in Notes 1, 10 and 11 to the consolidated financial statements, the Company employs risk management commodity contracts including physical and financial forward purchase and sale contracts and, to a lesser extent, over-the-counter swaps and options to accomplish its risk management strategies. Certain over-the-counter and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. As disclosed by management, the fair value of these risk management commodity contracts is estimated based on the best market information available, including valuation models that estimate future energy prices based on existing market and broker quotes, and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment including forward market price assumptions. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. Management utilized such unobservable pricing inputs to value its Level 3 risk management commodity contract assets and liabilities, which totaled $294 million and $155 million, as of December 31, 2023, respectively.

The principal considerations for our determination that performing procedures relating to the valuation of Level 3 risk management commodity contracts is a critical audit matter are the significant judgment by management when developing the fair value of the commodity contracts; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence relating to the forward market price assumptions used in management's valuation models. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

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

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 26, 2024

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2023. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2023.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2023. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2023, 2022 and 2021
(in millions, except per-share and share amounts)

	Years Ended December 31, 2023	2022	2021
REVENUES			
Vertically Integrated Utilities	$ 11,303.7	$ 11,292.8	$ 9,852.2
Transmission and Distribution Utilities	5,677.2	5,489.6	4,464.1
Generation & Marketing	1,543.3	2,448.9	2,108.3
Other Revenues	458.1	408.2	367.4
TOTAL REVENUES	18,982.3	19,639.5	16,792.0
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	6,578.3	7,097.9	5,466.3
Other Operation	2,810.5	2,878.1	2,547.7
Maintenance	1,276.3	1,249.4	1,121.8
Loss on the Expected Sale of the Kentucky Operations	—	363.3	—
Asset Impairments and Other Related Charges	85.6	48.8	11.6
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	—	(37.0)	—
Gain on the Sale of Mineral Rights	—	(116.3)	—
Loss on the Sale of the Competitive Contracted Renewables Portfolio	92.7	—	—
Depreciation and Amortization	3,090.4	3,202.8	2,825.7
Taxes Other Than Income Taxes	1,492.3	1,469.8	1,407.6
TOTAL EXPENSES	15,426.1	16,156.8	13,380.7
OPERATING INCOME	3,556.2	3,482.7	3,411.3
Other Income (Expense):			
Other Income	63.4	11.6	41.4
Allowance for Equity Funds Used During Construction	174.9	133.7	139.7
Non-Service Cost Components of Net Periodic Benefit Cost	221.1	188.5	118.6
Interest Expense	(1,806.9)	(1,396.1)	(1,199.1)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	2,208.7	2,420.4	2,511.9
Income Tax Expense	54.6	5.4	115.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries	58.5	(109.4)	91.7
NET INCOME	2,212.6	2,305.6	2,488.1
Net Income (Loss) Attributable to Noncontrolling Interests	4.5	(1.6)	—
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2,208.1	$ 2,307.2	$ 2,488.1
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	518,903,682	511,841,946	500,522,177
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.26	$ 4.51	$ 4.97
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	520,206,258	513,484,609	501,784,032
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.24	$ 4.49	$ 4.96

See Notes to Financial Statements of Registrants beginning on page 63.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2023, 2022 and 2021
(in millions)

	Years Ended December 31,		
	2023	2022	2021
Net Income	$ 2,212.6	$ 2,305.6	$ 2,488.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(33.8), $21.6 and $66.6 in 2023, 2022 and 2021, Respectively	(127.0)	81.4	250.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(3.4), $(2.8) and $(2.2) in 2023, 2022 and 2021, Respectively	(12.6)	(10.4)	(8.1)
Pension and OPEB Funded Status, Net of Tax of $(4.3), $(41.3) and $7.3 in 2023, 2022 and 2021, Respectively	(16.3)	(155.4)	27.5
Reclassifications of KPCo Pension and OPEB Regulatory Assets, Net of Tax of $4.4, $(4.4) and $0 in 2023, 2022 and 2021, Respectively	16.7	(16.7)	—
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(139.2)	(101.1)	269.9
TOTAL COMPREHENSIVE INCOME	2,073.4	2,204.5	2,758.0
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	4.5	(1.6)	—
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2,068.9	$ 2,206.1	$ 2,758.0

See Notes to Financial Statements of Registrants beginning on page 63.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2023, 2022 and 2021
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2020	516.8	$ 3,359.3	$ 6,588.9	$ 10,687.8	$ (85.1)	$ 223.6	$ 20,774.5
Issuance of Common Stock	7.6	49.4	551.1				600.5
Common Stock Dividends				(1,507.7) (a)		(11.8)	(1,519.5)
Other Changes in Equity			32.6	(1.1)		16.3	47.8
Acquisition of Dry Lake Solar Project						18.9	18.9
Net Income				2,488.1		—	2,488.1
Other Comprehensive Income					269.9		269.9
TOTAL EQUITY – DECEMBER 31, 2021	524.4	3,408.7	7,172.6	11,667.1	184.8	247.0	22,680.2
Issuance of Common Stock	0.7	4.4	822.1				826.5
Common Stock Dividends				(1,628.7) (a)		(16.5)	(1,645.2)
Other Changes in Equity			56.3			0.1	56.4
Net Income (Loss)				2,307.2		(1.6)	2,305.6
Other Comprehensive Loss					(101.1)		(101.1)
TOTAL EQUITY – DECEMBER 31, 2022	525.1	3,413.1	8,051.0	12,345.6	83.7	229.0	24,122.4
Issuance of Common Stock	2.3	14.8	984.8				999.6
Common Stock Dividends				(1,752.3) (a)		(8.1)	(1,760.4)
Other Changes in Equity			38.1	(1.0)		0.2	37.3
Disposition of Competitive Contracted Renewables Portfolio						(186.4)	(186.4)
Net Income				2,208.1		4.5	2,212.6
Other Comprehensive Loss					(139.2)		(139.2)
TOTAL EQUITY – DECEMBER 31, 2023	527.4	$ 3,427.9	$ 9,073.9	$ 12,800.4	$ (55.5)	$ 39.2	$ 25,285.9

(a) Cash dividends declared per AEP common share were $3.37, $3.17 and $3.00 for the years ended December 31, 2023, 2022 and 2021, respectively.

See Notes to Financial Statements of Registrants beginning on page 63.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2023 and 2022
(in millions)

	December 31, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 330.1	$ 509.4
Restricted Cash (December 31, 2023 and 2022 Amounts Include $48.9 and $47.1, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)	48.9	47.1
Other Temporary Investments (December 31, 2023 and 2022 Amounts Include $205 and $182.9, Respectively, Related to EIS and Transource Energy)	214.3	187.6
Accounts Receivable:		
Customers	1,029.9	1,145.1
Accrued Unbilled Revenues	179.5	322.9
Pledged Accounts Receivable – AEP Credit	1,249.4	1,207.4
Miscellaneous	48.7	49.7
Allowance for Uncollectible Accounts	(60.1)	(57.1)
Total Accounts Receivable	2,447.4	2,668.0
Fuel	853.7	435.1
Materials and Supplies	1,025.8	915.1
Risk Management Assets	217.5	348.8
Accrued Tax Benefits	156.2	99.4
Regulatory Asset for Under-Recovered Fuel Costs	514.0	1,310.0
Prepayments and Other Current Assets	274.2	255.0
TOTAL CURRENT ASSETS	6,082.1	6,775.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,329.5	25,834.2
Transmission	35,934.1	33,266.9
Distribution	28,989.9	27,138.8
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	6,484.9	5,971.8
Construction Work in Progress	5,508.0	4,809.7
Total Property, Plant and Equipment	101,246.4	97,021.4
Accumulated Depreciation and Amortization	24,553.0	23,682.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	76,693.4	73,339.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,092.4	4,762.0
Securitized Assets	336.3	446.0
Spent Nuclear Fuel and Decommissioning Trusts	3,860.2	3,341.2
Goodwill	52.5	52.5
Long-term Risk Management Assets	321.2	284.1
Operating Lease Assets	620.2	645.5
Deferred Charges and Other Noncurrent Assets	3,625.7	3,757.4
TOTAL OTHER NONCURRENT ASSETS	13,908.5	13,288.7
TOTAL ASSETS	$ 96,684.0	$ 93,403.3

See Notes to Financial Statements of Registrants beginning on page 63.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2023 and 2022
(dollars in millions)

	December 31, 2023	December 31, 2022
CURRENT LIABILITIES		
Accounts Payable	$ 2,032.5	$ 2,670.8
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	888.0	750.0
Other Short-term Debt	1,942.2	3,362.2
Total Short-term Debt	2,830.2	4,112.2
Long-term Debt Due Within One Year (December 31, 2023 and 2022 Amounts Include $207.2 and $218.2, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)	2,490.5	2,486.4
Risk Management Liabilities	229.6	145.2
Customer Deposits	423.7	408.8
Accrued Taxes	1,800.1	1,714.6
Accrued Interest	410.2	336.5
Obligations Under Operating Leases	115.7	113.6
Other Current Liabilities	1,251.1	1,278.2
TOTAL CURRENT LIABILITIES	11,583.6	13,266.3
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2023 and 2022 Amounts Include $556.3 and $755.3, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)	37,652.7	34,314.6
Long-term Risk Management Liabilities	241.8	345.2
Deferred Income Taxes	9,415.7	8,896.9
Regulatory Liabilities and Deferred Investment Tax Credits	8,182.4	8,115.6
Asset Retirement Obligations	2,972.5	2,879.3
Employee Benefits and Pension Obligations	241.7	257.3
Obligations Under Operating Leases	519.4	552.5
Deferred Credits and Other Noncurrent Liabilities	545.8	607.3
TOTAL NONCURRENT LIABILITIES	59,772.0	55,968.7
TOTAL LIABILITIES	71,355.6	69,235.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Contingently Redeemable Performance Share Awards	42.5	45.9
TOTAL MEZZANINE EQUITY	42.5	45.9
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2023	2022
Shares Authorized	600,000,000	600,000,000
Shares Issued	527,369,157	525,099,321

	December 31, 2023	December 31, 2022
(1,184,572 and 11,233,240 Shares were Held in Treasury as of December 31, 2023 and 2022, Respectively)	3,427.9	3,413.1
Paid-in Capital	9,073.9	8,051.0
Retained Earnings	12,800.4	12,345.6
Accumulated Other Comprehensive Income (Loss)	(55.5)	83.7
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	25,246.7	23,893.4
Noncontrolling Interests	39.2	229.0
TOTAL EQUITY	25,285.9	24,122.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 96,684.0	$ 93,403.3

See Notes to Financial Statements of Registrants beginning on page 63.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2023, 2022 and 2021
(in millions)

	Years Ended December 31, 2023	2022	2021
OPERATING ACTIVITIES			
Net Income	$ 2,212.6	$ 2,305.6	$ 2,488.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	3,090.4	3,202.8	2,825.7
Rockport Plant, Unit 2 Lease Amortization	—	—	135.4
Deferred Income Taxes	185.1	(137.2)	107.6
Loss on the Expected Sale of the Kentucky Operations	—	363.3	—
Loss on the Sale of the Competitive Contracted Renewables Portfolio	92.7	—	—
Asset Impairments and Other Related Charges	85.6	48.8	11.6
Impairment of Equity Method Investment	19.0	188.0	—
Allowance for Equity Funds Used During Construction	(174.9)	(133.7)	(139.7)
Mark-to-Market of Risk Management Contracts	8.8	15.5	112.3
Amortization of Nuclear Fuel	96.6	82.9	85.3
Property Taxes	(41.1)	(41.2)	(68.0)
Deferred Fuel Over/Under-Recovery, Net	892.8	(319.2)	(1,647.9)
Gain on the Sale of Mineral Rights	—	(116.3)	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	—	(37.0)	—
Change in Regulatory Assets	(315.8)	(46.7)	(238.9)
Change in Other Noncurrent Assets	(465.1)	(187.7)	(126.6)
Change in Other Noncurrent Liabilities	29.0	337.8	206.4
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	236.5	(681.7)	(119.7)
Fuel, Materials and Supplies	(504.0)	(313.9)	300.2
Accounts Payable	(253.2)	489.2	200.6
Accrued Taxes, Net	22.5	105.4	218.7
Rockport Plant, Unit 2 Operating Lease Payments	—	—	(147.7)
Other Current Assets	(43.9)	109.0	(151.3)
Other Current Liabilities	(161.4)	54.3	(212.2)
Net Cash Flows from Operating Activities	5,012.2	5,288.0	3,839.9
INVESTING ACTIVITIES			
Construction Expenditures	(7,378.3)	(6,671.7)	(5,659.6)
Purchases of Investment Securities	(2,863.6)	(2,784.2)	(1,955.1)
Sales of Investment Securities	2,795.1	2,743.8	1,901.4
Acquisitions of Nuclear Fuel	(128.2)	(100.7)	(104.5)
Acquisitions of Renewable Energy Facilities	(155.2)	(1,207.3)	(767.2)
Proceeds from Sales of Assets	1,341.4	218.0	118.9
Other Investing Activities	122.1	50.3	32.2
Net Cash Flows Used for Investing Activities	(6,266.7)	(7,751.8)	(6,433.9)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	999.6	826.5	600.5
Issuance of Long-term Debt	5,462.8	4,649.7	6,486.3
Issuance of Short-term Debt with Original Maturities greater than 90 Days	1,069.9	833.9	1,393.3
Change in Short-term Debt with Original Maturities less than 90 Day, Net	(1,223.1)	1,650.4	(487.3)
Retirement of Long-term Debt	(2,196.1)	(2,345.4)	(2,989.3)
Redemption of Short-term Debt with Original Maturities greater than 90 Days	(1,128.8)	(986.1)	(771.3)
Principal Payments for Finance Lease Obligations	(68.3)	(309.5)	(64.0)
Dividends Paid on Common Stock	(1,760.4)	(1,645.2)	(1,519.5)
Other Financing Activities	(78.6)	(105.4)	(41.6)
Net Cash Flows from Financing Activities	1,077.0	2,568.9	2,607.1
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(177.5)	105.1	13.1
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	556.5	451.4	438.3
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 379.0	$ 556.5	$ 451.4

See Notes to Financial Statements of Registrants beginning on page 63.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

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

Note	Registrant	Page Number
Organization and Summary of Significant Accounting Policies	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	64
New Accounting Standards	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	78
Comprehensive Income	AEP	79
Rate Matters	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	81
Effects of Regulation	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	91
Commitments, Guarantees and Contingencies	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	108
Acquisitions, Dispositions and Impairments	AEP, AEPTCo, PSO, SWEPCo	114
Benefit Plans	AEP, AEP Texas, APCo, I&M, OPCo, PSO, SWEPCo	117
Business Segments	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	133
Derivatives and Hedging	AEP, AEP Texas, APCo, I&M, OPCo, PSO, SWEPCo	137
Fair Value Measurements	AEP, AEP Texas, APCo, I&M, OPCo, PSO, SWEPCo	146
Income Taxes	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	157
Leases	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	163
Financing Activities	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	168
Stock-based Compensation	AEP	177
Related Party Transactions	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	181
Variable Interest Entities and Equity Method Investments	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	184
Property, Plant and Equipment	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	191
Revenue from Contracts with Customers	AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO, SWEPCo	197

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

ORGANIZATION

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

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

The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, AEP operated competitive wind and solar farms prior to the sale of AEP Renewables' competitive contracted renewables portfolio in August 2023. I&M provides barging services to both affiliated and nonaffiliated companies.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over certain issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

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

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers continue to pay for certain legacy deferred generation-related costs through PUCO approved riders. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has one active REP in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market.

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

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

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

Principles of Consolidation

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

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income.

AEP, I&M, PSO and SWEPCo have undivided ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Equity Method Investments and Note 18 - Property, Plant and Equipment for additional information.

Accounting for the Effects of Cost-Based Regulation

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

Use of Estimates

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

Cash and Cash Equivalents

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

Restricted Cash (Applies to AEP, AEP Texas 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 statement of cash flows:

	December 31, 2023		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 330.1	$ 0.1	$ 5.0
Restricted Cash	48.9	34.0	14.9
Total Cash, Cash Equivalents and Restricted Cash	$ 379.0	$ 34.1	$ 19.9

	December 31, 2022		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 509.4	$ 0.1	$ 7.5
Restricted Cash	47.1	32.7	14.4
Total Cash, Cash Equivalents and Restricted Cash	$ 556.5	$ 32.8	$ 21.9

Other Temporary Investments (Applies to AEP)

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

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR, which carries these inventories at the lower of average cost or net realizable value. Materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Uncollectible Accounts

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

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

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

Generally, AEP Credit recognizes bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. The assessment is performed separately for each participating AEP subsidiary, which inherently contemplates any differences in geographical risk characteristics for the allowance for uncollectible accounts. From January 2022 through August 2023, KPCo ceased selling accounts receivable to AEP Credit due to the planned sale of KPCo to Liberty. During this time period, KPCo recognized an allowance for uncollectible accounts on its balance sheet for its accounts receivables using the same assessment methodology used for AEP Credit's receivables. In September 2023, KPCo resumed selling accounts receivable to AEP Credit, due to the termination of the sale to Liberty. For receivables related to APCo's West Virginia operations, the allowance for uncollectible accounts is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable.

For customer accounts receivables relating to risk management activities, accounts receivable are reviewed for potential credit losses at a specific counterparty level basis. For AEP Texas, allowances for uncollectible accounts are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recognized based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

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

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

Significant Customers of AEP Texas: NRG Energy and TXU Energy	**2023**	**2022**	**2021**
Percentage of Total Revenues	41 %	45 %	43 %
Percentage of Accounts Receivable – Customers	34 %	42 %	41 %

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

Significant Customers of AEPTCo: AEP Subsidiaries	**2023**	**2022**	**2021**
Percentage of Total Revenues	79 %	79 %	79 %
Percentage of Total Accounts Receivable	60 %	72 %	81 %

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

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

In regulated jurisdictions, the Registrants record renewable energy credits (RECs) at cost. For AEP's competitive generation business, management records RECs at the lower of cost or net realizable value. The Registrants follow the inventory model for these RECs. RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs.

Property, Plant and Equipment

Regulated

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

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

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

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

Nonregulated

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

Allowance for Funds Used During Construction and Interest Capitalization

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

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal-mining facilities. I&M records ARO for the decommissioning of the Cook Plant. AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned, inflation, and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

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

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

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

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

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Purchased Electricity, Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is an expectation that refunds or recoveries will extend beyond a one year period, based on a company's filing with a commission or a commission directive. These deferrals are incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. The Registrants share the majority of their Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, non-existent or applicable to merchant operations, changes in fuel costs or sharing of Off-system Sales impact earnings.

Revenue Recognition

Regulatory Accounting

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

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

Retail and Wholesale Supply and Delivery of Electricity

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

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by the Registrants in the fourth quarter of each calendar year and a final annual true-up is recognized by the Registrants in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 19 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

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

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. 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. Realized gains and losses on cash flow hedges are recorded in Total Revenues or Purchased Electricity depending on the nature of the risk being hedged. Derivative purchases elected normal used to serve accrual based obligations are recorded in Purchased Electricity on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

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

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

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

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

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

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

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

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

Maintenance

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

Income Taxes and Investment and Production Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

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

AEP and subsidiaries apply the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the utility is able to utilize the ITC on a stand-alone basis. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by the Registrants. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows and presented as gross within the Supplementary Cash Flow Information.

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

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries is accounted for as an allocation through equity. The consolidated NOL of the AEP System is allocated to each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System NOL, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Excise Taxes (Applies to all Registrants except AEPTCo)

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

Debt

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

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

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

AEPSC sponsors a qualified pension plan and two unfunded non-qualified pension plans. Substantially all AEP subsidiary employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. AEPSC also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Registrant Subsidiaries account for their participation in the AEPSC sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

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

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

Benefit Plans

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

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

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

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

Pension Plan Assets	Target
Equity	30 %
Fixed Income	54 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	58 %
Fixed Income	41 %
Cash and Cash Equivalents	1 %

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

For equity investments, the concentration limits are generally as follows:

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

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

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

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2023 and 2022, the fair value of securities on loan as part of the program was $62 million and $83 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2023 and 2022.

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

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

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

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

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

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies 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. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss) (Applies to AEP only)

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

Stock-Based Compensation Plans

As of December 31, 2023, AEP had performance shares and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, all outstanding performance shares and restricted stock units settle in AEP common stock. The impact of AEP's stock-based compensation plan is insignificant to the financial statements of the Registrant Subsidiaries.

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

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

AEP compensates their non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. Prior to June 2022, these stock units were payable in cash to directors after their service ended and are now payable in AEP common stock.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2023, 2022 and 2021 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2023, 2022 and 2021, compensation costs are included in Net Income for the performance shares, career shares, restricted stock units, the non-employee director stock units and other qualified and non-qualified deferred compensation plans that provide an investment in or an investment return equivalent to that of AEP common stock. Compensation costs may also be capitalized. See Note 15 - Stock-based Compensation for additional information.

Equity Method Investments in Unconsolidated Entities (Applies to AEP and SWEPCo)

The equity method of accounting is used for equity investments where either AEP or SWEPCo exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in

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

As of December 31, 2023, AEP's significant equity method investments include ETT and DHLC. In August 2023, AEP disposed of four joint venture interests as a part of the sale of AEP Renewables' competitive contracted renewables portfolio. Prior to the sale, these joint venture interests were accounted for as equity method investments. See the "Disposition of the Competitive Contracted Renewables Portfolio" section of Note 7 and the "AEP Wind Holdings, LLC " section of Note 17 for additional information.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Years Ended December 31,					
	2023		2022		2021	
	(in millions, except per-share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 2,208.1		$ 2,307.2		$ 2,488.1	
Weighted-Average Number of Basic AEP Common Shares Outstanding	518.9	$ 4.26	511.8	$ 4.51	500.5	$ 4.97
Weighted-Average Dilutive Effect of Stock-Based Awards	1.3	(0.02)	1.7	(0.02)	1.3	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	520.2	$ 4.24	513.5	$ 4.49	501.8	$ 4.96

There were no antidilutive shares outstanding as of December 31, 2023, 2022 and 2021.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2023, 2022 and 2021:

2023

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,927.5	$ 380.0	$ 393.8	$ 571.1	$ 439.8	$ 315.8	$ 240.3	$ 323.4
Amortization of Certain Securitized Assets	91.9	91.9	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	71.0	(3.4)	—	0.8	30.2	0.4	15.2	19.4
Total Depreciation and Amortization	$ 3,090.4	$ 468.5	$ 393.8	$ 571.9	$ 470.0	$ 316.2	$ 255.5	$ 342.8

2022

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 3,072.8	$ 363.5	$ 346.2	$ 576.1	$ 511.9	$ 293.1	$ 226.2	$ 319.3
Amortization of Certain Securitized Assets	93.3	93.3	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	36.7	(4.4)	—	(0.2)	15.3	1.2	3.9	5.5
Total Depreciation and Amortization	$ 3,202.8	$ 452.4	$ 346.2	$ 575.9	$ 527.2	$ 294.3	$ 230.1	$ 324.8

2021

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,717.1	$ 327.2	$ 297.3	$ 547.0	$ 424.9	$ 301.1	$ 185.9	$ 292.9
Amortization of Certain Securitized Assets	64.2	64.2	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	44.4	(4.4)	—	(0.8)	21.1	2.2	10.7	2.1
Total Depreciation and Amortization	$ 2,825.7	$ 387.0	$ 297.3	$ 546.2	$ 446.0	$ 303.3	$ 196.6	$ 295.0

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2023	2022	2021
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 1,673.5	$ 1,286.3	$ 1,137.2
Income Taxes	78.4	116.8	13.2
Sale of Transferable Tax Credits	(102.0)	—	—
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	48.7	31.8	287.6
Construction Expenditures Included in Current Liabilities as of December 31,	842.4	1,258.9	1,180.4
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	24.2	—	—
Noncash Contribution of Assets to Cedar Creek Project	—	—	(9.3)
Noncontrolling Interest Assumed - Dry Lake Solar Project	—	—	35.3
Noncash Increase in Noncurrent Assets from the Sale of the Competitive Contracted Renewables Portfolio	74.7	—	—

2. NEW ACCOUNTING STANDARDS

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

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

ASU 2023-09 "Improvements to Income Tax Disclosures" (ASU 2023-09)

In December 2023, the FASB issued ASU 2023-09, to address investors' suggested enhancements to (a) better understand an entity's exposure to potential changes in jurisdictional tax legislation and the ensuing risks and opportunities, (b) assess income tax information that affects cash flow forecasts and capital allocation decisions and (c) identify potential opportunities to increase future cash flows.

The new standard requires an annual rate reconciliation disclosure of the following categories regardless of materiality: state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items and changes in unrecognized tax benefits.

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.

The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has not yet made a decision to early adopt the amendments to this standard or how to apply them.

ASU 2023-07 "Improvements to Reportable Segment Disclosures" (ASU 2023-07)

In November 2023, the FASB issued ASU 2023-07, to address investors' observations that there is limited information disclosed about segment expenses and to better understand expense categories and amounts included in segment profit or loss. The new standard requires annual and interim disclosure of (a) the categories and amounts of significant segment expenses (determined by management using both qualitative and quantitative factors) that are regularly provided to the chief operating decision maker (CODM) and included within each reported measure of segment profit or loss, (b) the amounts and a qualitative description of "other segment items", defined as the difference between reported segment revenues less the significant segment expenses and each reported measure of segment profit or loss disclosed, (c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources and (e) a requirement that entities with a single reportable segment provide all disclosures required by ASU 2023-07 and all existing segment disclosures in Topic 280. Additionally, this new standard allows disclosure of one or more of additional profit or loss measures if the CODM uses more than one measure provided that at least one of the disclosed measures is determined in a manner "most consistent with the measurement principles under GAAP". If multiple measures are presented, additional disclosure is required about how the CODM uses each measure to assess performance and decide how to allocate resources.

The amendments in the new standard are effective on a retrospective basis for all entities for fiscal years beginning after December 15, 2023 and interim periods within fiscal periods beginning after December 15, 2024 with early adoption permitted. Management does not plan to early adopt the amendments to this standard.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to AEP only. The impact of AOCI is not material to the financial statements of the Registrant Subsidiaries.

Presentation of Comprehensive Income

The following tables provide AEP's components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2023, 2022 and 2021. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional information.

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2023	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2022	$ 223.5	$ 0.3	$ 105.2	$ (245.3)	$ 83.7
Change in Fair Value Recognized in AOCI, Net of Tax	(175.8)	(6.4)	—	(16.3)	(198.5)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	72.2	—	—	—	72.2
Interest Expense (a)	—	(2.4)	—	—	(2.4)
Amortization of Prior Service Cost (Credit)	—	—	(21.2)	—	(21.2)
Amortization of Actuarial (Gains) Losses	—	—	5.2	—	5.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	72.2	(2.4)	(16.0)	—	53.8
Income Tax (Expense) Benefit	15.0	(0.4)	(3.4)	—	11.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	57.2	(2.0)	(12.6)	—	42.6
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI, before Income Tax (Expense) Benefit	—	—	—	21.1	21.1
Income Tax (Expense) Benefit	—	—	—	4.4	4.4
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI, Net of Income Tax (Expense) Benefit	—	—	—	16.7	16.7
Net Current Period Other Comprehensive Income (Loss)	(118.6)	(8.4)	(12.6)	0.4	(139.2)
Balance in AOCI as of December 31, 2023	$ 104.9	$ (8.1)	$ 92.6	$ (244.9)	$ (55.5)

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2022	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2021	$ 163.7	$ (21.3)	$ 115.6	$ (73.2)	$ 184.8
Change in Fair Value Recognized in AOCI, Net of Tax	477.3	18.4	—	(155.4)	340.3
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (a)	0.1	—	—	—	0.1
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(528.6)	—	—	—	(528.6)
Interest Expense (a)	—	4.0	—	—	4.0
Amortization of Prior Service Cost (Credit)	—	—	(21.8)	—	(21.8)
Amortization of Actuarial (Gains) Losses	—	—	8.6	—	8.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(528.5)	4.0	(13.2)	—	(537.7)
Income Tax (Expense) Benefit	(111.0)	0.8	(2.8)	—	(113.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(417.5)	3.2	(10.4)	—	(424.7)
Reclassifications of KPCo Pension and OPEB Regulatory Assets to AOCI, before Income Tax (Expense) Benefit	—	—	—	(21.1)	(21.1)
Income Tax (Expense) Benefit	—	—	—	(4.4)	(4.4)
Reclassifications of KPCo Pension and OPEB Regulatory Assets to AOCI, Net of Income Tax (Expense) Benefit	—	—	—	(16.7)	(16.7)
Net Current Period Other Comprehensive Income (Loss)	59.8	21.6	(10.4)	(172.1)	(101.1)
Balance in AOCI as of December 31, 2022	$ 223.5	$ 0.3	$ 105.2	$ (245.3)	$ 83.7

For the Year Ended December 31, 2021	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2020	$ (60.6)	$ (47.5)	$ 123.7	$ (100.7)	$ (85.1)
Change in Fair Value Recognized in AOCI, Net of Tax	488.2	21.1	—	27.5	536.8
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (a)	0.7	—	—	—	0.7
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(334.8)	—	—	—	(334.8)
Interest Expense (a)	—	6.5	—	—	6.5
Amortization of Prior Service Cost (Credit)	—	—	(19.4)	—	(19.4)
Amortization of Actuarial (Gains) Losses	—	—	9.1	—	9.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(334.1)	6.5	(10.3)	—	(337.9)
Income Tax (Expense) Benefit	(70.2)	1.4	(2.2)	—	(71.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(263.9)	5.1	(8.1)	—	(266.9)
Net Current Period Other Comprehensive Income (Loss)	224.3	26.2	(8.1)	27.5	269.9
Balance in AOCI as of December 31, 2021	$ 163.7	$ (21.3)	$ 115.6	$ (73.2)	$ 184.8

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

4. RATE MATTERS

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

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

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

AEP Texas Interim Transmission and Distribution Rates

Through December 31, 2023, AEP Texas' cumulative revenues from interim base rate increases that are subject to a prudency review is approximately $987 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.

APCo and WPCo Rate Matters (Applies to AEP and APCo)

2020-2022 Virginia Triennial Review

In March 2023, APCo submitted its 2020-2022 Virginia triennial review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $213 million annual increase in Virginia base rates based upon a proposed 10.6% return on common equity. The requested annual increase includes $47 million related to vegetation management and a $35 million increase in depreciation expense. The requested increase in depreciation expense reflects, among other things, the impacts of incremental investments made since APCo's last depreciation study using property balances as of December 31, 2022. Effective January 1, 2023 and in accordance with past Virginia SCC directives, APCo implemented updated Virginia depreciation rates. APCo's proposed revenue requirement also includes the recovery of certain costs incurred that partially contributed to APCo's calculated earnings shortfall for the 2020-2022 triennial period. For triennial review periods in which a Virginia utility earns below its authorized ROE band, the utility may file to recover expenses incurred, up to the bottom of the authorized ROE band, related to certain categories of costs, including system restoration costs for severe weather events.

In August 2023, APCo, Virginia Staff and intervening parties reached a settlement agreement that included the following: (a) a $127 million annual increase in Virginia base rates, (b) a 9.5% ROE, (c) updated depreciation rates that reflect a 2040 Amos Plant retirement date, (d) approval of a regulatory asset, including tax gross-up, to be recovered over three years starting in 2024 related to major storm expenses incurred during the 2020-2022 triennial period when APCo under-earned in Virginia, (e) approval of the revenue requirement impact of net operating loss carryforward related to income taxes and approval of deferral authority for corporate alternative minimum taxes incurred and (f) approval of the revenue requirement impact of an increase in vegetation management costs with certain costs subject to over-/under-recovery accounting. In November 2023, the Virginia SCC issued a final order approving the settlement agreement as described above with new rates taking effect in January 2024.

ENEC (Expanded Net Energy Cost) Filings

In April 2023, APCo and WPCo (the Companies) submitted their 2023 annual ENEC filing with the WVPSC, proposing two alternatives to increase ENEC rates effective September 1, 2023 and to resolve the Companies' open 2021 and 2022 ENEC filings. The first alternative was a $293 million annual increase in ENEC rates comprised of an $89 million increase for current year ENEC expense and a $200 million annual increase for the recovery of the Companies' February 28, 2023 ENEC under-recovery balances over three years, including debt and equity carrying costs. The second alternative was an $89 million annual increase in ENEC rates with the Companies securitizing approximately $1.9 billion of assets, including: (a) $553 million relating to ENEC under-recoveries as of February 28, 2023, (b) $88 million relating to major storm expense deferrals and (c) $1.2 billion relating to APCo's West Virginia jurisdictional book values of the Amos and Mountaineer Plants and forecasted CCR and ELG investments at these generating facilities.

In September 2023, the WVPSC issued an order on the 2023 ENEC filing approving an $89 million annual increase in ENEC surcharge rates for the Companies' forecasted costs for the period September 2023 through August 2024.

In January 2024, the WVPSC issued an order resolving the Companies' 2021-2023 ENEC cases. In the order, the WVPSC: (a) disallowed $232 million in ENEC under-recovered costs as of February 28, 2023 ($136 million related to APCo) and (b) approved the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023 ($174 million related to APCo) plus a 4% carrying charge rate over a ten-year recovery period starting September 1, 2024. As of December 31, 2023, the Companies' financial statements reflect the impact of the disallowance. In February 2024, the Companies filed briefs with the

West Virginia Supreme Court to initiate an appeal of this order. The Companies will submit their annual ENEC update filing with the WVPSC in the second quarter of 2024 proposing that updated ENEC rates become effective September 1, 2024.

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 December 31, 2023, AEP's share of ETT's cumulative revenues that are subject to a prudency review is approximately $1.7 billion. A base rate review could produce a refund to customers 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, 2025, during which the $1.7 billion of cumulative revenues above will be subject to review.

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

Michigan Power Supply Cost Recovery (PSCR)

In April 2023, I&M received intervenor testimony in I&M's 2021 PSCR Reconciliation for the 12-month period ending December 31, 2021, recommending disallowances of purchased power costs of $18 million associated with the OVEC Inter-Company Power Agreement (ICPA) and the UPA with AEGCo that were alleged to be above market in applying the MPSC's Code of Conduct rules. Michigan staff submitted testimony in I&M's 2021 PSCR Reconciliation with no recommended disallowances for PSCR costs incurred, including those associated with the OVEC ICPA and the AEGCo UPA. Michigan staff also recommended several options to address I&M's shortfall in achieving Michigan's annual one percent energy waste reduction savings level, resulting in potential future disallowed costs of up to approximately $14 million. In June 2023, Michigan staff submitted rebuttal testimony to update their calculation of the 2021 market proxy price resulting in a recommended disallowance of approximately $1 million related to the OVEC ICPA.

In January 2024, I&M received staff testimony in I&M's 2022 PSCR Reconciliation for the 12-month period ending December 31, 2022 recommending disallowances of purchased power costs of $2 million associated with the OVEC ICPA that were alleged to be above market in applying the MPSC's Code of Conduct rules. Similar to the 2021 PSCR Reconciliation, Michigan staff also recommended several options to address I&M's shortfall in achieving Michigan's annual one percent energy waste reduction savings level, resulting in potential future disallowed costs of up to approximately $6 million.

MPSC orders on I&M's 2021 and 2022 PSCR Reconciliations are expected in the first half of 2024. If any PSCR costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2023 Indiana Base Rate Case

In August 2023, I&M filed a request with the IURC for a $116 million annual increase in Indiana base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a proposed capital structure of 48.8% debt and 51.2% common equity. I&M proposed that the annual increase in base rates be implemented in two steps, with the first increase effective in mid-2024, following an IURC order, and the second increase effective in January 2025. The proposed annual increase includes a $41 million increase related to depreciation expense, driven by increased depreciation rates and increased capital investments, and a $15 million increase related to storm expenses. I&M's Indiana base case filing requests recovery of certain historical period regulatory asset balances and proposes deferral accounting for certain future investments and tax related issues, including corporate alternative minimum tax expense and PTCs related to the Cook Plant.

In December 2023, I&M and intervenors reached a settlement agreement that was submitted to the IURC recommending a two-step increase in Indiana rates with a $28 million annual increase effective upon an IURC order and the remaining $34 million annual increase effective in January 2025. The recommended revenue increase includes: (a) a 9.85% ROE, (b) a two-step update of I&M's capital structure with a capital structure of 50% for both debt and common equity effective upon an IURC order and I&M will submit an updated capital structure in January 2025 with the common equity component adjusted to no more than 51.2%, (c) a $25 million increase related to depreciation expense and (d) an $11 million increase related to storm expenses.

A hearing was held in January 2024 and an order is expected in the second quarter of 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

2023 Michigan Base Rate Case

In September 2023, I&M filed a request with the MPSC for a $34 million annual increase in Michigan base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a capital structure of 49.4% debt and 50.6% common equity. The proposed annual increase includes an $11 million annual increase in depreciation expense driven by increased capital investment. I&M's Michigan base case filing requests recovery of certain historical period regulatory asset balances and proposes deferral accounting for certain future investments and tax related issues, including corporate alternative minimum tax expense and PTCs related to the Cook Plant.

In January 2024, Michigan Staff and various intervenors submitted testimony recommending changes in base rates ranging from a $6 million annual decrease to a $19 million annual increase. These changes are based on ROEs ranging from 9.7% to 9.9% and capital structures ranging from 49.4% debt and 50.6% equity to 52% debt and 48% equity. Intervenors also proposed in testimony certain disallowances related to existing regulatory assets totaling approximately $5 million, the exclusion of CAMT from any future deferrals and the prospective inclusion of PTCs related to the Cook Plant in I&M's PSCR.

A hearing was held in February 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

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

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. In February 2024, KPCo filed a motion to strike and exclude intervenor testimony in its entirety on the grounds that issues raised are outside the scope of the proceeding and because the testimony is largely unreasoned, unsupported, and provides no evidentiary value. A hearing is expected in 2024. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce net income and cash flows and impact financial condition.

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $94 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. The filing proposes no changes in depreciation rates and an annual level of storm restoration expense in base rates of approximately $1 million. KPCo also proposed to discontinue tracking of PJM transmission costs through a rider, and to instead collect an annual level of costs through base rates. In addition, KPCo has proposed a rider to recover certain distribution reliability investments and related incremental operation and maintenance expenses. KPCo also requested a prudency determination and recovery mechanism for approximately $16 million of purchased power costs not recoverable through its FAC since its last base case. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. As of December 31, 2023, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $553 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

In conjunction with its June 2023 filing, KPCo further requested to finance, through the issuance of securitization bonds, approximately $471 million of regulatory assets recorded as of June 2023 including: (a) $289 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $52 million of deferred purchased power expenses and (d) $51 million of under-recovered purchased power rider costs. Plant retirement costs and deferred purchased power expenses have been deemed prudent in prior KPSC decisions. KPCo has requested a prudency determination in this proceeding for the deferred storm costs and under-recovered purchase power rider costs since the last base case.

In November 2023, KPCo filed an uncontested settlement agreement with the KPSC, that included an annual base rate increase of $75 million, based upon a 9.75% ROE. Settlement parties agreed that the KPSC should approve KPCo's securitization request, and that the approximately $471 million regulatory assets requested for securitization are comprised of prudently incurred costs. The settlement does not modify KPCo's proposal to discontinue tracking of PJM transmission costs through a rider, and to instead collect an annual level of costs through base rates. The settlement approved KPCo's request to implement a rider to recover certain distribution reliability investments. Under the terms of the settlement, KPCo agreed to forgo recovery of approximately $16 million of purchased power costs not recoverable through the FAC since KPCo's last base case and excluded a return on its stand-alone NOLC deferred tax asset from the base rate revenue requirement while it seeks a private letter ruling from the IRS. Other differences between KPCo's requested annual base rate increase and the uncontested settlement agreement are primarily due to exclusion of certain employee-related expenses from the revenue requirement.

In January 2024, consistent with the November 2023 uncontested settlement agreement, the KPSC issued a financing order approving KPCo's securitization request and concluding that costs requested for recovery were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement, and issuance that were not reflected in KPCo's proposal. As a result, in January 2024, KPCo filed a request for rehearing with the KPSC to clarify certain aspects of these additional requirements. In February 2024, the KPSC denied KPCo's rehearing requests. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the second half of 2024, subject to market conditions. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of $60 million based upon a 9.75% ROE effective with billing cycles mid-January 2024. The order reduced KPCo's base rate revenue requirement by $14 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. The KPSC denied implementation of a rider to recover certain distribution reliability investments. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court, challenging among other aspects of the order the $14 million base rate revenue requirement reduction.

Fuel Adjustment Clause (FAC) Review

In December 2023, KPCo received intervenor testimony in its FAC review for the two-year period ending October 31, 2022, recommending a disallowance ranging from $44 million to $60 million of its total $432 million purchased power cost recoveries as a result of proposed modifications to the ratemaking methodology that limits purchased power costs recoverable through the FAC. A hearing was held in February 2024. If any fuel costs are not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Rockport Offset Recovery

In January 2024, KPCo filed an application with the KPSC seeking to recover an allowed cost (Rockport Offset) of $41 million in accordance with the terms of the settlement agreement in the 2017 Kentucky Base Rate Case permitting KPCo to use the level of non-fuel, non-environmental Rockport Plant UPA expense included in base rates to earn its authorized ROE in 2023 since the Rockport UPA ended in December 2022. An estimated Rockport Offset of $23 million was recovered through a rider, subject to true-up, during the 12-months ended December 2023. KPCo is requesting to recover the remaining $18 million Rockport Offset true-up over a 12-month period beginning March 2024, also through a rider. The Rockport Offset true-up is not yet reflected in revenue, as KPCo has not met the requirements of alternative revenue recognition in accordance with the accounting guidance for "Regulated Operations". In February 2024, the KPSC issued an order allowing KPCo to collect the remaining $18 million through interim rates, subject to refund, over twelve months starting in March 2024. Intervenor testimony is expected in April 2024 and an order is expected in the second quarter of 2024. If the Rockport Offset is not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

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

OVEC Cost Recovery Audits

In December 2021, as part of OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPCo during the 2018-2019 audit period were imprudent and should be disallowed. In May 2022, intervenors filed for rehearing on the 2016-2017 OVEC cost recovery audit period claiming the PUCO's April 2022 order to adopt the findings of the audit report were unjust, unlawful and unreasonable for multiple reasons, including the position that OPCo recovered imprudently incurred costs. In June 2022, the PUCO granted rehearing on the 2016-2017 audit period for purposes of further consideration.

In May 2023, as part of the OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPCo during the 2020 audit period were imprudent and should be disallowed. A hearing was held in November 2023.

Management disagrees with these claims and is unable to predict the impact of these disputes. If any costs are disallowed or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Ohio ESP Filings

In January 2023, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments, proposed new riders and the continuation and modification of certain existing riders, including the DIR, effective June 2024 through May 2030. The proposal includes a return on common equity of 10.65% on capital costs for certain riders. In June 2023, intervenors filed testimony opposing OPCo's plan for various new riders and modifications to existing riders, including the DIR. In September 2023, OPCo and certain intervenors filed a settlement agreement with the PUCO addressing the ESP application. The settlement included a four year term from June 2024 through May 2028, an ROE of 9.7% and continuation of a number of riders including the DIR subject to revenue caps. An order from the PUCO is expected in the first quarter of 2024. If OPCo is ultimately not permitted to fully collect its ESP rates it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

2022 Oklahoma Base Rate Case

In November 2022, PSO filed a request with the OCC for an annual base rate increase of $294 million based upon a 10.4% ROE with a capital structure of 45.4% debt and 54.6% common equity. The requested $294 million annual base rate increase, net of existing rider revenues and certain incremental renewable facility benefits expected to be provided to customers through riders, represented a requested annual increase in rates of $173 million and included a $47 million annual depreciation expense increase related to the accelerated depreciation recovery of the Northeastern Plant, Unit 3 through 2026, and a $16 million annual amortization expense increase to recover intangible plant over a 5-year useful life instead of a 10-year useful life. PSO's request also included recovery of the 155 MW Rock Falls Wind Facility through base rates to aid PSO's near-term capacity needs and support compliance with SPP's 2023 increased capacity planning reserve margin requirements.

In November 2023, the OCC issued a final order approving an annual base rate increase of $131 million based upon a 9.3% ROE. As a result of the final order, PSO is required to exclude Rock Falls Wind Facility from recovery through base rates until a future base case since the facility was placed into service for PSO customers after the conclusion of the customary six-month post-test year period for ratemaking adjustments. In addition, PSO must provide Rock Falls Wind Facility benefits in excess of $21 million on an annual basis to customers through a rider. The order also stipulates PSO's proposals related to inclusion of a stand-alone NOLC deferred tax asset in rate base will be addressed in a future proceeding, upon receipt of a private letter ruling from the IRS. Effective January 2024, interim rates implemented in May 2023 concluded and updated rates and tariffs were implemented in accordance with the final order. In January 2024, refund of the $18 million interim rate over collection began and will be competed no later than April 2024, in compliance with the final order. In December 2023, PSO appealed certain elements of the OCC's final order to the Supreme Court of the State of Oklahoma.

2024 Oklahoma Base Rate Case

In January 2024, PSO filed a request with the OCC for a $218 million annual base rate increase based upon a 10.8% ROE with a capital structure of 48.9% debt and 51.1% common equity. PSO requested an expanded transmission cost recovery rider and a mechanism to recover generation costs necessary to comply with SPP's 2023 increased capacity planning reserve margin requirements. PSO's request reflects recovery of Northeastern Plant, Unit 3 through 2040.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

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

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of 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 August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment 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. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCT. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was remanded to the PUCT for future proceedings. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

On December 14, 2023, the PUCT approved a preliminary order stating the PUCT will not address SWEPCo's request that would allow the PUCT to find cause to allow SWEPCo to exceed the Texas jurisdictional capital cost cap in the current remand proceeding. As a result of the PUCT's approval of the preliminary order, SWEPCo believes it is probable the PUCT will disallow capitalized AFUDC in excess of the Texas jurisdictional capital cost cap and recorded a pretax, non-cash disallowance of $86 million in the fourth quarter of 2023. Such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis. On December 21, 2023, SWEPCo filed a motion with the PUCT for reconsideration of the preliminary order. In January 2024, the PUCT denied the motion for reconsideration of the preliminary order.

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. In January 2024, the PUCT established a procedural schedule for the remand proceeding. Supplemental testimony from SWEPCo is due in March 2024, intervenor and staff testimony is due in April 2024 and a hearing is scheduled for May 2024. Although SWEPCo does not currently believe any refunds are probable of occurring, SWEPCo estimates it could be required to make customer refunds, including interest, ranging from $0 to $200 million related to revenues collected from February 2013 through December 2023.

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 related to limiting SWEPCo's recovery of AFUDC on Turk Plant and recovery of Welsh Plant, Unit 2. If certain parts of the PUCT order are overturned, 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. 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 January 2022, the PUCT issued a final order approving an annual revenue increase of $39 million based upon a 9.25% ROE. The order also includes: (a) rates implemented retroactively back to March 18, 2021, (b) $5 million of the proposed increase related to vegetation management, (c) $2 million annually to establish a storm catastrophe reserve and (d) the creation of a rider to 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 to be recovered as a regulatory asset through 2046. As a result of the final order, SWEPCo recorded a disallowance of $12 million in 2021 associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging several errors in the order, which include challenges of the approved ROE, the denial of a reasonable return or carrying costs on the Dolet Hills Power Station and the calculation of the Texas jurisdictional share of the storm catastrophe reserve. In April 2022, the PUCT denied the motion for rehearing. In May

2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order.

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. SWEPCo's requested annual increase includes accelerated depreciation related to the Dolet Hills Power Station, Pirkey Power Plant and Welsh Plant, all of which were or are expected to be retired early. SWEPCo also included recovery of Welsh Plant, Unit 2 over the blended useful life of Welsh Plant, Units 1 and 3. SWEPCo subsequently revised the requested annual increase to $95 million to reflect removing hurricane storm restoration costs from the base case filing, to modify the proposed recovery of the Dolet Hills Power Station and revisions to various proposed amortizations. The hurricane costs have been requested in a separate storm filing. See "2021 Louisiana Storm Cost Filing" below for more information.

In January 2023, the LPSC approved a settlement which provides for an annual revenue increase of $27 million based upon a 9.5% ROE and includes: (a) a $21 million increase in base rates effective February 2023, (b) a $14 million rider to recover costs of the Dolet Hills Power Station and Pirkey Plant including a return, (c) an $8 million reduction in fuel rates, (d) adoption of a 3-year formula rate term subject to an earnings band and (e) the recovery of certain incremental SPP charges net of associated revenue and the Louisiana jurisdictional share of the return on and of projected transmission capital investment outside of the earnings band. The settlement agreement did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which is being addressed in a separate proceeding.

The primary differences between SWEPCo's requested annual rate increase and the agreed upon settlement increase are primarily due to: (a) a reduction in the requested ROE, (b) recovery of the Dolet Hills Power Station and Pirkey Plant over ten years in a separate rider mechanism as opposed to base rates with accelerated depreciation rates, (c) maintaining existing depreciation rates for Welsh Plant, Units 1 and 3 and (d) the severing of SWEPCo's proposed adjustment to include a stand-alone NOLC deferred tax asset in rate base.

In January 2023, a hearing was held related to the inclusion of a stand-alone NOLC deferred tax asset in rate base. In September 2023, an order was received from the LPSC directing SWEPCo to seek a private letter ruling from the IRS to address the matter.

2021 Louisiana Storm Cost Filing

In 2020, Hurricanes Laura and Delta caused power outages and extensive damage to the SWEPCo service territories, primarily impacting the Louisiana jurisdiction. Following both hurricanes, the LPSC issued orders allowing Louisiana utilities, including SWEPCo, to establish regulatory assets to track and defer expenses associated with these storms. In February 2021, severe winter weather impacted the Louisiana jurisdiction and in March 2021, the LPSC approved the deferral of incremental storm restoration expenses related to the winter storm. In March 2023, SWEPCo and the LPSC staff filed a joint stipulation and settlement agreement with the LPSC which confirmed the prudency of $150 million of deferred incremental storm restoration expenses. The agreement also authorized an interim carrying charge at a rate of 3.125% until the recovery mechanism is determined in phase two of this proceeding. In April 2023, the LPSC issued an order approving the stipulation and settlement agreement. In July 2023, SWEPCo submitted additional information in phase two of this proceeding to obtain a financing order and prudency review of capital investment. The procedural schedule for this case states that a hearing will take place in the second quarter of 2024.

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021, to February 20, 2021, SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are shown in the table below:

Jurisdiction	December 31, 2023	December 31, 2022	Approved Recovery Period	Approved Carrying Charge
	(in millions)			
Arkansas	$ 54.2	$ 74.9	6 years	(a)
Louisiana	97.2	121.7	(b)	(b)
Texas	101.9	132.4	5 years	1.65%
Total	$ 253.3	$ 329.0		

(a) SWEPCo is permitted to record carrying costs on the unrecovered balance of fuel costs at a weighted-cost of capital approved by the APSC. The APSC will conclude an audit of these costs in 2024. A hearing is scheduled for May 2024.

(b) In March 2021, the LPSC approved a special order granting a temporary modification to the FAC and shortly after SWEPCo began recovery of its Louisiana jurisdictional share of these fuel costs based on a five-year recovery period inclusive of an interim carrying charge equal to the prime rate. The special order states the fuel and purchased power costs incurred will be subject to a future LPSC audit.

If SWEPCo is unable to recover any of the costs relating to the extraordinary fuel and purchases of electricity, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

FERC 2019 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. In March 2022, the FERC issued an order granting the formal challenge on several issues and denying the formal challenge on other issues. Management has determined that the result of the order had an immaterial impact to the financial statements of AEP, AEPTCo, PSO and SWEPCo. In November 2022, certain joint customers appealed the FERC denial of issues to the U.S. Court of Appeals for the District of Columbia Circuit. In January 2024, the court agreed with the FERC's order and denied the certain joint customers petition for review.

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 has an ownership interest in 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 Maryland. In May 2021, the Pennsylvania Public Utility Commission (PAPUC) denied the IEC certificate for siting and construction of the portion in Pennsylvania. Transource Energy appealed the PAPUC ruling in Pennsylvania state court and challenged the ruling before the United States District Court for the Middle District of Pennsylvania. In May 2022, the Pennsylvania state court issued an order affirming the PAPUC decision as to state law claims. In December 2023, the United States District Court for the Middle District of Pennsylvania granted summary judgment in favor of Transource Energy, finding that the PAPUC decision violated federal law and the United States Constitution. In January 2024, the PAPUC filed an appeal with the United States Court of Appeals for the Third Circuit. Additional regulatory proceedings before the PAPUC are expected to resume in 2024.

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. At that time, PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. PJM continues to evaluate reliability and market efficiency in the area. As of December 31, 2023, AEP's share of IEC capital expenditures was approximately $93 million, located in Total Property, Plant and Equipment - Net on AEP's balance sheets. 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.

FERC RTO Incentive Complaint (Applies to AEP, AEPTCo and OPCo)

In February 2022, the OCC filed a complaint against AEPSC, American Transmission Systems, Inc. and Duke Energy Ohio, alleging the 50 basis point RTO incentive included in Ohio Transmission Owners' respective transmission formula rates is not just and reasonable and therefore should be eliminated on the basis that RTO participation is not voluntary, but rather is required by Ohio law. In March 2022, AEPSC filed a motion to dismiss the OCC's February 2022 complaint with the FERC on the basis of certain deficiencies, including that the complaint fails to request relief that can be granted under FERC regulations because AEPSC is not a public utility nor does it have a transmission rate on file with the FERC. In December 2022, the FERC issued an order removing the 50 basis point RTO incentive from OPCo and OHTCo transmission formula rates effective the date of the February 2022 complaint filing and directed OPCo and OHTCo to provide refunds, with interest, within sixty days of the date of its order. In January 2023, both AEPSC and the OCC filed requests for rehearing with the FERC. In February 2023, in compliance with the FERC's December 2022 order, AEPSC submitted a filing to the FERC to update OPCo and OHTCo 2023 transmission formula rates to exclude the 50 basis point RTO incentive and provide refunds with interest. In April 2023, the FERC approved the updated transmission formula rates for OPCo and OHTCo and issued an Order on Rehearing affirming its December 2022 decision. During 2023, in compliance with FERC's December 2022 order, OPCo and OHTCo provided refunds including interest of $5 million and $13 million, respectively. This decision has been appealed to the U.S. Court of Appeals for the Sixth Circuit.

Request to Update AEGCo Depreciation Rates (Applies to AEP and I&M)

In October 2022, AEP, on behalf of AEGCo, submitted proposed revisions to AEGCo's depreciation rates for its 50% ownership interest in Rockport Plant, Unit 1 and Unit 2, reflected in the UPA between AEGCo and I&M. The proposed depreciation rates for these assets reflect an estimated 2028 retirement date for the Rockport Plant. AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 1 were based upon a December 31, 2028 estimated retirement date while AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 2 leasehold improvements were based upon a December 31, 2022 estimated retirement date in conjunction with the termination of the Rockport Plant, Unit 2 lease.

In December 2022, the FERC issued an order approving the proposed AEGCo Rockport depreciation rates effective January 1, 2023, subject to further review and a potential refund. The FERC established a separate proceeding to review: (a) AEGCo's acquisition value for the Rockport Plant, Unit 2 base generating asset (original cost and accumulated depreciation), (b) the appropriateness of including future capital additions as stated components in proposed depreciation rates, in light of the UPA's formula rate mechanism, (c) the appropriateness of applying two different depreciation rates to a single asset common to both units and (d) the accounting and regulatory treatment of Rockport Plant, Unit 2 costs of removal and related AROs. In August 2023, AEGCo reached a settlement agreement with the FERC Trial Staff that resolves all issues set for hearing. In September 2023, the settlement agreement was certified to the FERC as uncontested. An order from the FERC on this settlement agreement is expected in 2024. If the FERC finalizes the settlement agreement as proposed, management anticipates the results of the order will not have a material impact on financial condition, results of operations or cash flows.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge (Applies to AEP, AEPTCo, APCo, I&M, PSO and SWEPCo)

The Registrants transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2023, 2022 and 2021 by $60 million, $69 million and $78 million, respectively.

In March 2023 and May 2023, certain joint customers submitted a complaint and a formal challenge at the FERC related to the 2022 Annual Update of the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP, respectively. These challenges primarily relate to stand-alone treatment of NOLCs in the transmission formula rates of the AEP transmission owning subsidiaries. AEPSC, on behalf of the AEP transmission owning subsidiaries within PJM and SPP, filed answers to the joint formal challenge and complaint with the FERC in the second quarter of 2023.

In January 2024, the FERC issued two orders, granting the joint customers' challenges related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests with the FERC that it grant rehearing and reverse findings in its January 2024 orders or establish hearing procedures to address outstanding factual issues.

As a result of the January 2024 FERC orders, the Registrants' 2022 and 2023 income statements cumulatively reflect a provision for refund for the probable refund of all NOLC revenues included in transmission formula rates for years 2023, 2022 and 2021. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms. The FERC directed cash refunds with interest related to the 2021 rate year to occur through the annual update for the next rate year, which will be invoiced by PJM and SPP primarily in 2025. The Registrants have not yet been directed to make cash refunds related to the 2022 or 2023 rate years.

The FERC's January 2024 orders reduced AEP and AEPTCo's 2023 pretax net income by approximately $76 million and $74 million, respectively. The impact of the FERC's orders on the pretax net income of AEP's remaining Registrant Subsidiaries was not material.

Request to Update SWEPCo Generation Depreciation Rates (Applies to AEP and SWEPCo)

In October 2023, SWEPCo filed an application to revise its generation wholesale customer's contracts to reflect an increase in the annual revenue requirement of approximately $5 million for updated depreciation rates and allow for the return on and of FERC customers jurisdictional share of regulatory assets associated with retired plants. In November 2023, certain intervenors filed a motion with the FERC protesting and recommending the rejection of SWEPCo's filings. In December 2023, the FERC issued an order approving the proposed rates effective January 1, 2024, subject to further review and refund and established hearing and settlement proceedings. If SWEPCo is unable to recover the remaining regulatory assets associated with retired plants, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

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

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 is not deemed recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Regulated Generating Units that have been Retired

SWEPCo

In December 2021, the Dolet Hills Power Station was retired. As part of the 2020 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo's Texas jurisdictional share of the Dolet Hills Power Station through 2046, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $12 million in 2021. As part of the 2021 Arkansas Base Rate Case, the APSC authorized recovery of SWEPCo's Arkansas jurisdictional share of the Dolet Hills Power Station through 2027, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $2 million in the second quarter of 2022. Also, the APSC did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which will be addressed in a future proceeding. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Dolet Hills Power Station, through a separate rider, through 2032, but did not rule on the prudency of the early retirement of the plant, which is being addressed in a separate proceeding. See "2020 Texas Base Rate Case" and "2020 Louisiana Base Rate Case" sections of Note 4 for additional information.

In March 2023, the Pirkey Plant was retired. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana jurisdictional share of the Pirkey Plant, through a separate rider, through 2032. As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. In July 2023, Texas ALJs issued a proposal for decision that concluded the decision to retire the Pirkey Plant was prudent. In September 2023, the PUCT rejected the ALJs proposal for decision concluding the retirement of the Pirkey Plant was prudent. In the open meeting, the commissioners expressed their concerns that the analysis in support of SWEPCo's decision to retire the Pirkey Plant was not robust enough and that SWEPCo should have re-evaluated the decision following Winter Storm Uri. The treatment of the cost of recovery of the Pirkey Plant is expected to be addressed in a future rate case. As of December 31, 2023, the Texas jurisdictional share of the net book value of the Pirkey Plant was $67 million. To the extent any portion of the Texas jurisdictional share of the net book value of the Pirkey Plant is not recoverable, it could reduce future net income and cash flows and impact financial condition.

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. As part of the 2022 Oklahoma Base Rate Case, PSO will continue to recover Northeastern Plant, Unit 3 through 2040.

SWEPCo

In November 2020, management announced 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 December 31, 2023, 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	$ 104.5	$ 164.2	$ 20.5 (b)	2026	(c)	$ 15.0
Welsh Plant, Units 1 and 3	352.0	125.6	58.2 (d)	2028 (e)	(f)	38.6

(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 the removal of Northeastern Plant, Unit 3, after retirement.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with the removal of Welsh Plant, Units 1 and 3, after retirement.
(e) Represents projected retirement date of coal assets, units are being evaluated for conversion to natural gas after 2028.
(f) 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)

In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station. The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through rate riders. As of December 31, 2023, SWEPCo's share of the net investment in the Dolet Hills Power Station was $103 million, including materials and supplies, net of cost of removal collected in rates. Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of December 31, 2023, SWEPCo had a net under-recovered fuel balance of $77 million, inclusive of costs related to the Dolet Hills Power Station billed by DHLC, but excluding impacts of the February 2021 severe winter weather event.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $35 million of additional costs with a recovery period to be determined at a later date. In August 2022, the LPSC staff filed testimony recommending fuel disallowances of up to $55 million, including denial of recovery of the $35 million deferral, with refunds to customers over five years. In February 2024, an ALJ issued a final recommendation which included a proposed $55 million refund to customers and the denial of recovery of the $35 million deferral. SWEPCo filed a motion to present oral arguments with the LPSC to dispute the ALJ's recommendations. Management believes its financial statements adequately address the impact of the LPSC staff and ALJ recommendations. A decision from the LPSC is expected in the first quarter of 2024.

In March 2021, the APSC approved fuel rates that provide recovery of $20 million for the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $48 million of Oxbow mine related costs through 2035.

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

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

In March 2023, the Pirkey Plant was retired. SWEPCo is recovering, or will seek recovery of, the remaining net book value of Pirkey Plant non-fuel costs. As of December 31, 2023, SWEPCo's share of the net investment in the Pirkey Plant was $182 million, including materials and supplies, net of cost of removal. See the "Regulated Generating Units that have been Retired" section above for additional information. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased. Additionally, as of December 31, 2023, SWEPCo had a net under-recovered fuel balance of $77 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Remaining operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses.

In July 2023, the LPSC ordered that a separate proceeding be established to review the prudence of the decision to retire the Pirkey Plant, including the costs included in fuel for years starting in 2019 and after. In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $33 million of Sabine related fuel costs through 2035.

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

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining
Current Regulatory Assets	2023	2022	Recovery Period
	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 357.4	$ 625.7	1 year
Under-recovered Fuel Costs - does not earn a return	62.7	588.5	1 year
Unrecovered Winter Storm Fuel Costs - earns a return (a)	93.9	95.8	1 year
Total Current Regulatory Assets	$ 514.0	$ 1,310.0	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 125.6	$ 85.6	
Pirkey Plant Accelerated Depreciation	114.4	116.5	
Unrecovered Winter Storm Fuel Costs (a)	60.1	84.6	
Other Regulatory Assets Pending Final Regulatory Approval	49.8	68.9	
Total Regulatory Assets Currently Earning a Return	349.9	355.6	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	408.9	407.1	
2020-2022 Virginia Triennial Under-Earnings	—	37.9	
Other Regulatory Assets Pending Final Regulatory Approval	78.5	81.5	
Total Regulatory Assets Currently Not Earning a Return	487.4	526.5	
Total Regulatory Assets Pending Final Regulatory Approval	837.3	882.1	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (b)	664.2	689.9	23 years
Long-term Under-recovered Fuel Costs - West Virginia	291.5	—	11 years
Storm-Related Costs	170.9	8.4	5 years
Plant Retirement Costs - Asset Retirement Obligation Costs	110.8	110.6	19 years
Long-term Under-recovered Fuel Costs - Virginia	107.0	223.3	2 years
Unrecovered Winter Storm Fuel Costs (a)	99.3	148.6	4 years
Fuel Mine Closure Costs - Texas	74.3	—	12 years
Pirkey Plant Accelerated Depreciation - Louisiana	65.8	63.0	9 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	46.9	56.6	5 years
Kentucky Deferred Purchased Power Expenses	43.5	53.0	4 years
Ohio Basic Transmission Cost Rider	42.2	14.3	2 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station, Louisiana	40.8	45.1	9 years
Texas Mobile Temporary Emergency Electric Energy Facilities Rider	33.4	—	2 years
Environmental Control Projects	31.4	33.9	17 years
Meter Replacement Costs	23.5	34.2	4 years
Long-term Under-recovered Fuel Costs - Oklahoma	—	252.7	
Other Regulatory Assets Approved for Recovery	101.4	125.0	various
Total Regulatory Assets Currently Earning a Return	1,946.9	1,858.6	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,054.1	975.4	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	330.2	308.5	19 years
Unrealized Loss on Forward Commitments	131.4	40.1	9 years
Unamortized Loss on Reacquired Debt	97.2	104.1	25 years
Fuel and Purchased Power Adjustment Rider	68.3	76.3	2 years
Cook Plant Nuclear Refueling Outage Levelization	55.7	81.2	2 years
OVEC Purchased Power	50.1	—	2 years
Plant Retirement Costs - Unrecovered Plant, Texas	48.7	51.7	23 years
Storm-Related Costs	38.5	11.9	2 years
2020-2022 Virginia Triennial Under Earnings	37.4	—	4 years
Ohio Enhanced Service Reliability Plan	35.3	33.3	2 years
Ohio Distribution Investment Rider	35.3	2.3	2 years
Postemployment Benefits	30.6	32.1	3 years
Peak Demand Reduction/Energy Efficiency	23.9	41.7	3 years
Other Regulatory Assets Approved for Recovery	271.5	262.7	various
Total Regulatory Assets Currently Not Earning a Return	2,308.2	2,021.3	
Total Regulatory Assets Approved for Recovery	4,255.1	3,879.9	
Total Noncurrent Regulatory Assets	$ 5,092.4	$ 4,762.0	

(a) See “February 2021 Severe Winter Weather Impacts in SPP” section of SWEPCo Rate Matters in Note 4 for additional information.

(b) Northeastern Plant, Unit 3 is approved for recovery through 2040, but expected to retire in 2026. PSO records a regulatory asset for accelerated depreciation. See “Regulated Generating Units to be Retired” section above for additional information.

	AEP		
	December 31,		Remaining
	2023	2022	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 3.3	$ 1.4	1 year
Over-recovered Fuel Costs - does not pay a return	23.2	—	1 year
Total Current Regulatory Liabilities	$ 26.5	$ 1.4	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 103.1	$ 149.7	
Total Regulatory Liabilities Currently Paying a Return	103.1	149.7	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	103.1	—	
Other Regulatory Liabilities Pending Final Regulatory Determination	1.7	4.1	
Total Regulatory Liabilities Currently Not Paying a Return	104.8	4.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	207.9	153.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	3,563.5	3,392.4	(b)
Income Taxes, Net (a)	2,179.7	2,504.5	(c)
Rockport Plant, Unit 2 Accelerated Depreciation for Leasehold Improvements	44.9	53.8	5 years
Other Regulatory Liabilities Approved for Payment	35.0	32.7	various
Total Regulatory Liabilities Currently Paying a Return	5,823.1	5,983.4	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,721.9	1,318.5	(d)
Deferred Investment Tax Credits	154.5	237.3	31 years
Spent Nuclear Fuel	47.6	45.8	(d)
2017-2019 Virginia Triennial Revenue Provision	37.1	39.1	26 years
Demand Side Management	31.3	15.7	2 years
Over-recovered Fuel Costs - Ohio	26.1	32.2	9 years
PJM Transmission Enhancement Refund	22.8	34.1	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	14.1	34.2	2 years
OVEC Purchased Power	—	47.1	
Unrealized Gain on Forward Commitments	—	45.2	
Other Regulatory Liabilities Approved for Payment	96.0	129.2	various
Total Regulatory Liabilities Currently Not Paying a Return	2,151.4	1,978.4	
Total Regulatory Liabilities Approved for Payment	7,974.5	7,961.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,182.4	$ 8,115.6	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $228 million and $277 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.
(d) Relieved when plant is decommissioned.

Regulatory Assets:	AEP Texas December 31, 2023	2022	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Texas Mobile Generation Lease Payments	$ —	$ 17.6	
Total Regulatory Assets Currently Earning a Return	—	17.6	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	37.7	26.7	
Line Inspection Costs	5.7	4.5	
Vegetation Management Program	5.2	5.2	
Texas Retail Electric Provider Bad Debt Expense	4.0	4.1	
Other Regulatory Assets Pending Final Regulatory Approval	11.7	8.9	
Total Regulatory Assets Currently Not Earning a Return	64.3	49.4	
Total Regulatory Assets Pending Final Regulatory Approval	64.3	67.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Texas Mobile Temporary Emergency Electric Energy Facilities Rider	33.4	—	2 years
Meter Replacement Costs	9.4	16.1	2 years
Other Regulatory Assets Approved for Recovery	0.7	1.4	various
Total Regulatory Assets Currently Earning a Return	43.5	17.5	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	183.2	173.2	12 years
Peak Demand Reduction/Energy Efficiency	9.2	11.9	2 years
Vegetation Management Program	6.8	12.1	2 years
Storm-Related Costs	4.3	8.5	2 years
Other Regulatory Assets Approved for Recovery	4.0	8.1	various
Total Regulatory Assets Currently Not Earning a Return	207.5	213.8	
Total Regulatory Assets Approved for Recovery	251.0	231.3	
Total Noncurrent Regulatory Assets	$ 315.3	$ 298.3	

Regulatory Liabilities:	AEP Texas December 31, 2023	2022	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 13.0	$ 13.0	
Total Regulatory Liabilities Currently Paying a Return	13.0	13.0	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	1.5	1.8	
Total Regulatory Liabilities Currently Not Paying a Return	1.5	1.8	
Total Regulatory Liabilities Pending Final Regulatory Determination	14.5	14.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	797.1	766.8	(b)
Income Taxes, Net (a)	412.0	431.6	(c)
Other Regulatory Liabilities Approved for Payment	3.8	4.3	various
Total Regulatory Liabilities Currently Paying a Return	1,212.9	1,202.7	
Regulatory Liabilities Currently Not Paying a Return			
Transition and Restoration Charges	26.6	29.4	6 years
Other Regulatory Liabilities Approved for Payment	7.4	12.7	various
Total Regulatory Liabilities Currently Not Paying a Return	34.0	42.1	
Total Regulatory Liabilities Approved for Payment	1,246.9	1,244.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,261.4	$ 1,259.6	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets.

Regulatory Assets:	AEPTCo December 31, 2023	AEPTCo December 31, 2022	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Not Earning a Return			
PJM/SPP Annual Formula Rate True-up	$ 3.1	$ 7.2	2 years
Total Regulatory Assets Approved for Recovery	3.1	7.2	
Total Noncurrent Regulatory Assets	$ 3.1	$ 7.2	

Regulatory Liabilities:	AEPTCo December 31, 2023	AEPTCo December 31, 2022	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 8.7	$ 8.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	8.7	8.7	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	466.3	358.8	(b)
Income Taxes, Net (a)	308.7	355.8	(c)
Total Regulatory Liabilities Approved for Payment	775.0	714.6	
Total Noncurrent Regulatory Liabilities	$ 783.7	$ 723.3	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $13 million and $16 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.

Regulatory Assets:	APCo December 31, 2023	APCo December 31, 2022	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 147.4	$ 180.7	1 year
Under-recovered Fuel Costs - does not earn a return	8.0	292.4	1 year
Total Current Regulatory Assets	$ 155.4	$ 473.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.6	$ 7.0	
Total Regulatory Assets Currently Earning a Return	0.6	7.0	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - West Virginia	91.5	72.6	
Plant Retirement Costs - Asset Retirement Obligation Costs	25.9	25.9	
2020-2022 Virginia Triennial Under-Earnings	—	37.9	
Other Regulatory Assets Pending Final Regulatory Approval	7.5	1.1	
Total Regulatory Assets Currently Not Earning a Return	124.9	137.5	
Total Regulatory Assets Pending Final Regulatory Approval	125.5	144.5	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Long-term Under-recovered Fuel Costs - West Virginia	154.2	—	11 years
Long-term Under-recovered Fuel Costs - Virginia	107.0	223.3	2 years
Plant Retirement Costs - Unrecovered Plant	72.0	75.6	20 years
Other Regulatory Assets Approved for Recovery	7.1	0.4	various
Total Regulatory Assets Currently Earning a Return	340.3	299.3	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	324.7	303.1	15 years
Pension and OPEB Funded Status	115.8	108.3	12 years
Unamortized Loss on Reacquired Debt	70.7	74.4	22 years
2020-2022 Virginia Triennial Under-Earnings	37.4	—	4 years
Virginia Transmission Rate Adjustment Clause	25.5	18.7	2 years
Unrealized Loss on Forward Commitments	21.9	—	3 years
Peak Demand Reduction/Energy Efficiency	15.0	15.8	3 years
Postemployment Benefits	14.9	13.7	3 years
Vegetation Management Program - West Virginia	12.9	13.7	2 years
Excess SO_2 Allowance Inventory - Virginia	11.8	—	9 years
Virginia Generation Rate Adjustment Clause	10.9	8.0	2 years
Virginia Clean Economy Act	8.0	16.7	2 years
2017-2019 Virginia Triennial Under-Earnings	2.3	30.1	1 year
Other Regulatory Assets Approved for Recovery	17.5	12.3	various
Total Regulatory Assets Currently Not Earning a Return	689.3	614.8	
Total Regulatory Assets Approved for Recovery	1,029.6	914.1	
Total Noncurrent Regulatory Assets	$ 1,155.1	$ 1,058.6	

Regulatory Liabilities:	APCo December 31, 2023	2022	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 7.9	$ 30.5	
Total Regulatory Liabilities Currently Paying a Return	7.9	30.5	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	19.7	—	
Total Regulatory Liabilities Currently Not Paying a Return	19.7	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	27.6	30.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	759.6	713.5	(b)
Income Taxes, Net (a)	240.1	291.3	(c)
Deferred Investment Tax Credits	0.3	0.3	30 years
Total Regulatory Liabilities Currently Paying a Return	1,000.0	1,005.1	
Regulatory Liabilities Currently Not Paying a Return			
2017-2019 Virginia Triennial Revenue Provision	37.1	39.1	26 years
Over-recovered Deferred Wind Power Costs - Virginia	2.6	13.6	2 years
Unrealized Gain on Forward Commitments	—	34.5	
Other Regulatory Liabilities Approved for Payment	14.6	20.8	various
Total Regulatory Liabilities Currently Not Paying a Return	54.3	108.0	
Total Regulatory Liabilities Approved for Payment	1,054.3	1,113.1	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,081.9	$ 1,143.6	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $35 million and $19 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.

Regulatory Assets:	I&M December 31, 2023	2022	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Michigan - earns a return	$ 14.8	$ 9.0	1 year
Under-recovered Fuel Costs, Indiana - does not earn a return	—	38.1	
Total Current Regulatory Assets	$ 14.8	$ 47.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.2	$ 0.1	
Total Regulatory Assets Currently Earning a Return	0.2	0.1	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - Indiana	29.7	21.6	
Other Regulatory Assets Pending Final Regulatory Approval	3.3	2.0	
Total Regulatory Assets Currently Not Earning a Return	33.0	23.6	
Total Regulatory Assets Pending Final Regulatory Approval	33.2	23.7	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	122.5	147.0	5 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	46.9	56.6	5 years
Cook Plant Uprate Project	22.9	25.3	10 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan, FERC	11.1	12.1	11 years
Cook Plant Turbine - Indiana	8.4	9.0	15 years
Other Regulatory Assets Approved for Recovery	17.5	20.6	various
Total Regulatory Assets Currently Earning a Return	229.3	270.6	
Regulatory Assets Currently Not Earning a Return			
Cook Plant Nuclear Refueling Outage Levelization	55.7	81.2	2 years
Pension and OPEB Funded Status	25.4	26.9	12 years
Excess SO_2 Allowance Inventory - Indiana	14.8	—	5 years
Unamortized Loss on Reacquired Debt	11.8	12.9	25 years
Environmental Cost Rider - Indiana	8.1	6.6	2 years
Postemployment Benefits	7.0	7.7	3 years
Demand Side Management - Indiana	—	10.3	
Other Regulatory Assets Approved for Recovery	21.0	19.7	various
Total Regulatory Assets Currently Not Earning a Return	143.8	165.3	
Total Regulatory Assets Approved for Recovery	373.1	435.9	
Total Noncurrent Regulatory Assets	$ 406.3	$ 459.6	

Regulatory Liabilities:	I&M December 31, 2023	2022	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Indiana - does not pay a return	$ 23.2	$ —	1 year
Total Current Regulatory Liabilities	$ 23.2	$ —	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a) (b)	$ (103.0)	$ (87.7)	
Total Regulatory Liabilities Currently Paying a Return	(103.0)	(87.7)	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	22.8	—	
Total Regulatory Liabilities Currently Not Paying a Return	22.8	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	(80.2)	(87.7)	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	168.1	170.7	(c)
Income Taxes, Net (a)	116.8	168.6	(d)
Renewable Energy Surcharge - Michigan	26.6	23.2	2 years
Other Regulatory Liabilities Approved for Payment	0.1	3.0	various
Total Regulatory Liabilities Currently Paying a Return	311.6	365.5	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,721.9	1,318.5	(e)
Spent Nuclear Fuel	47.6	45.8	(e)
Demand Side Management - Indiana	16.7	—	2 years
Deferred Investment Tax Credits	15.8	17.4	27 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	14.1	34.2	2 years
Other Regulatory Liabilities Approved for Payment	4.8	8.5	various
Total Regulatory Liabilities Currently Not Paying a Return	1,820.9	1,424.4	
Total Regulatory Liabilities Approved for Payment	2,132.5	1,789.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,052.3	$ 1,702.2	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Represents an income tax related regulatory asset, which is presented within net regulatory liabilities on the balance sheet.
(c) Relieved as removal costs are incurred.
(d) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $25 million and $42 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.
(e) Relieved when plant is decommissioned.

Regulatory Assets:	OPCo December 31, 2023	2022	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - does not earn a return	$ —	$ 3.8	1 year
Total Current Regulatory Assets	$ —	$ 3.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	$ 23.6	$ 33.8	
Total Regulatory Assets Pending Final Regulatory Approval	23.6	33.8	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Basic Transmission Cost Rider	42.2	14.3	2 years
Ohio Distribution Decoupling	1.8	19.5	2 years
Ohio Economic Development Rider	—	1.1	
Total Regulatory Assets Currently Earning a Return	44.0	34.9	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	147.1	142.7	12 years
Unrealized Loss on Forward Commitments	50.8	40.0	9 years
OVEC Purchased Power	50.1	—	2 years
Ohio Enhanced Service Reliability Plan	35.3	33.3	2 years
Ohio Distribution Investment Rider	35.3	2.3	2 years
Storm-Related Costs	30.9	—	1 year
Smart Grid Costs	26.3	25.4	2 years
Other Regulatory Assets Approved for Recovery	11.6	14.9	various
Total Regulatory Assets Currently Not Earning a Return	387.4	258.6	
Total Regulatory Assets Approved for Recovery	431.4	293.5	
Total Noncurrent Regulatory Assets	$ 455.0	$ 327.3	

Regulatory Liabilities:	OPCo December 31, 2023	2022	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	$ 57.0	$ —	
Other Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	57.2	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	475.5	466.5	(a)
Income Taxes, Net (b)	408.2	451.9	(c)
Total Regulatory Liabilities Currently Paying a Return	883.7	918.4	
Regulatory Liabilities Currently Not Paying a Return			
Over-recovered Fuel Costs	26.1	32.2	9 years
Peak Demand Reduction/Energy Efficiency	23.2	23.6	2 years
PJM Transmission Enhancement Refund	9.8	14.7	2 years
OVEC Purchased Power	—	47.1	
Other Regulatory Liabilities Approved for Payment	3.6	7.8	various
Total Regulatory Liabilities Currently Not Paying a Return	62.7	125.4	
Total Regulatory Liabilities Approved for Payment	946.4	1,043.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,003.6	$ 1,044.0	

(a) Relieved as removal costs are incurred.
(b) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(c) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $132 million and $162 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.

Regulatory Assets:	PSO		
	December 31, 2023	December 31, 2022	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 118.3	$ 178.7	1 year
Total Current Regulatory Assets	$ 118.3	$ 178.7	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	$ 88.5	$ 25.5	
Other Regulatory Assets Pending Final Regulatory Approval	0.2	0.1	
Total Regulatory Assets Pending Final Regulatory Approval	88.7	25.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (a)	254.1	240.6	23 years
Storm-Related Costs	26.2	8.4	5 years
Environmental Control Projects	22.5	23.9	17 years
Meter Replacement Costs	14.1	18.1	4 years
Long-term Under-recovered Fuel Costs - Oklahoma	—	252.7	
Other Regulatory Assets Approved for Recovery	8.4	9.1	various
Total Regulatory Assets Currently Earning a Return	325.3	552.8	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	62.6	55.2	12 years
Unrealized Loss on Forward Commitments	29.9	—	2 years
Other Regulatory Assets Approved for Recovery	16.2	20.1	various
Total Regulatory Assets Currently Not Earning a Return	108.7	75.3	
Total Regulatory Assets Approved for Recovery	434.0	628.1	
Total Noncurrent Regulatory Assets	$ 522.7	$ 653.7	

(a) Northeastern Plant, Unit 3 is approved for recovery through 2040, but expected to retire in 2026. PSO records a regulatory asset for accelerated depreciation. See "Regulated Generating Units to be Retired" section above for additional information.

Regulatory Liabilities:	PSO		
	December 31, 2023	December 31, 2022	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ —	$ 51.3	
Total Regulatory Liabilities Currently Paying a Return	—	51.3	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	1.2	—	
Total Regulatory Liabilities Currently Not Paying a Return	1.2	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	1.2	51.3	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	395.7	380.1	(b)
Asset Removal Costs	317.5	316.3	(c)
Total Regulatory Liabilities Currently Paying a Return	713.2	696.4	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	47.2	48.2	18 years
Other Regulatory Liabilities Approved for Payment	4.0	13.2	various
Total Regulatory Liabilities Currently Not Paying a Return	51.2	61.4	
Total Regulatory Liabilities Approved for Payment	764.4	757.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 765.6	$ 809.1	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.

(b) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $51 million and $21 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 1 year.

(c) Relieved as removal costs are incurred.

	SWEPCo		
	December 31,		Remaining Recovery Period
	2023	2022	
Regulatory Assets:	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 76.9	$ 257.2	1 year
Unrecovered Winter Storm Fuel Costs - earns a return (b)	93.9	95.8	1 year
Total Current Regulatory Assets	$ 170.8	$ 353.0	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 125.6	$ 85.6	
Pirkey Plant Accelerated Depreciation	114.4	116.5	
Unrecovered Winter Storm Fuel Costs (b)	60.1	84.6	
Dolet Hills Power Station Accelerated Depreciation (c)	12.0	9.7	
Other Regulatory Assets Pending Final Regulatory Approval	26.0	34.5	
Total Regulatory Assets Currently Earning a Return	338.1	330.9	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - Louisiana, Texas	56.0	151.5	
Asset Retirement Obligation - Louisiana	—	11.8	
Other Regulatory Assets Pending Final Regulatory Approval	13.7	16.0	
Total Regulatory Assets Currently Not Earning a Return	69.7	179.3	
Total Regulatory Assets Pending Final Regulatory Approval	407.8	510.2	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Storm-Related Costs - Louisiana	144.7	—	2 years
Unrecovered Winter Storm Fuel Costs (b)	99.3	148.6	4 years
Fuel Mine Closure Costs - Texas	74.3	—	12 years
Pirkey Plant Accelerated Depreciation - Louisiana	65.8	63.0	9 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	44.4	13.1	19 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station - Louisiana	40.8	45.1	9 years
Environmental Controls Projects	8.9	10.0	9 years
Plant Retirement Costs - Unrecovered Plant, Welsh Plant, Unit 2 - Louisiana	—	35.2	
Other Regulatory Assets Approved for Recovery	4.9	6.8	various
Total Regulatory Assets Currently Earning a Return	483.1	321.8	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	109.2	96.2	12 years
Plant Retirement Costs - Unrecovered Plant, Texas	48.7	51.7	23 years
North Central Wind Rider	20.2	6.4	2 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	17.3	21.1	4 years
Unrealized Loss on Forward Commitments	15.4	—	2 years
Other Regulatory Assets Approved for Recovery	30.1	35.0	various
Total Regulatory Assets Currently Not Earning a Return	240.9	210.4	
Total Regulatory Assets Approved for Recovery	724.0	532.2	
Total Noncurrent Regulatory Assets	$ 1,131.8	$ 1,042.4	

(a) Amounts include Arkansas and Texas jurisdictions.
(b) See “February 2021 Severe Winter Weather Impacts in SPP” section of SWEPCo Rate Matters in Note 4 for additional information.
(c) Amounts include the FERC jurisdiction.

	SWEPCo		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	2023	2022	
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return (a)	$ 3.3	$ 1.4	1 year
Total Current Regulatory Liabilities	$ 3.3	$ 1.4	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (b)	$ 7.0	$ 7.0	
Total Regulatory Liabilities Pending Final Regulatory Determination	7.0	7.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	443.2	481.2	(c)
Income Taxes, Net (b)	292.4	327.6	(d)
Other Regulatory Liabilities Approved for Payment	4.4	2.2	various
Total Regulatory Liabilities Currently Paying a Return	740.0	811.0	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Approved for Payment	9.1	7.7	various
Total Regulatory Liabilities Currently Not Paying a Return	9.1	7.7	
Total Regulatory Liabilities Approved for Payment	749.1	818.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 756.1	$ 825.7	

(a) Amounts include Louisiana jurisdiction.
(b) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(c) Relieved as removal costs are incurred.
(d) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

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

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

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2023:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,126.7	$ 1,260.7	$ 313.5	$ 256.1	$ 2,957.0
Energy and Capacity Purchase Contracts	186.4	412.3	308.8	419.8	1,327.3
Total	$ 1,313.1	$ 1,673.0	$ 622.3	$ 675.9	$ 4,284.3

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 595.2	$ 626.1	$ 99.5	$ —	$ 1,320.8
Energy and Capacity Purchase Contracts	40.1	80.2	65.5	75.9	261.7
Total	$ 635.3	$ 706.3	$ 165.0	$ 75.9	$ 1,582.5

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 144.4	$ 232.3	$ 130.8	$ 241.6	$ 749.1
Energy and Capacity Purchase Contracts	127.0	253.8	236.6	182.2	799.6
Total	$ 271.4	$ 486.1	$ 367.4	$ 423.8	$ 1,548.7

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 33.4	$ 66.6	$ 66.3	$ 102.6	$ 268.9

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 31.5	$ 36.6	$ —	$ —	$ 68.1
Energy and Capacity Purchase Contracts	56.6	139.3	88.0	56.3	340.2
Total	$ 88.1	$ 175.9	$ 88.0	$ 56.3	$ 408.3

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 109.2	$ 48.1	$ —	$ —	$ 157.3
Energy and Capacity Purchase Contracts	16.4	26.2	2.2	—	44.8
Total	$ 125.6	$ 74.3	$ 2.2	$ —	$ 202.1

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

GUARANTEES

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

Letters of Credit (Applies to AEP, AEP Texas, APCo and I&M)

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 2027 and 2025, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2023, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2023 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 257.0	January 2024 to November 2024
AEP Texas	1.8	July 2024
APCo	6.3	September 2024
I&M	2.9	September 2024

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2023, there were no material liabilities recorded for any indemnifications.

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

Lease Obligations

Certain Registrants lease equipment under master lease agreements. See "Master Lease Agreements" section of Note 13 for additional information.

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)

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

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2023, AGR, APCo, OPCo and SWEPCo are named as a Potentially Responsible Party (PRP) for one, one, two and one sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2023, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

I&M owns and operates the two-unit 2,296 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. Management is currently evaluating applying for license extensions for both units. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2021. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2.2 billion in 2021 non-discounted dollars, with additional ongoing costs of $7 million per year for post decommissioning storage of SNF and an eventual cost of $33 million for the subsequent decommissioning of the SNF storage facility, also in 2021 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $2 million, $2 million and $4 million for the years ended December 31, 2023, 2022 and 2021, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2023 and 2022, the total decommissioning trust fund balances were $3.5 billion and $3.0 billion, respectively. The increase in the trust fund balance was driven by favorable investment performance in 2023. Trust fund earnings increase the fund assets and may decrease the amount remaining to be recovered from customers. Trust fund losses decrease the fund assets and may increase the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

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

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2023 and 2022, fees and related interest of $300 million and $286 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $348 million and $330 million, respectively, to pay the fee, were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $21 million, $3 million and $14 million in 2023, 2022 and 2021, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2023. The proceeds reduced costs for dry cask storage. As of December 31, 2023 and 2022, I&M deferred $12 million and $21 million, respectively, in Prepayments and Other Current Assets and $9 million and $3 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover a nuclear incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by a nuclear incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $500 million. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $42 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $16.3 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $500 million of primary coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $332 million per nuclear incident on Cook Plant's reactors payable in annual installments of $49 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $500 million through commercially available insurance. The next level of liability coverage of up to $15.8 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

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

Litigation Related to Ohio House Bill 6 (HB 6) (Applies to AEP and OPCo)

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, AEP, with assistance from outside advisors, conducted a review of the circumstances surrounding the passage of the bill. Management does 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 U. S. District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. In December 2021, the district court issued an opinion and order dismissing the securities litigation complaint with prejudice, determining that the complaint failed to plead any actionable misrepresentations or omissions. The plaintiffs did not appeal the ruling.

In January 2021, an AEP shareholder filed a derivative action in the U.S. 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 court entered a scheduling order in the New York state court derivative action staying the case other than with respect to briefing the motion to dismiss. AEP filed substantive and forum-based motions to dismiss in April 2022. In June 2022, the Ohio state court entered an order continuing the stays of that case until the final resolution of the consolidated derivative actions pending in Ohio federal district court. In September 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiff subsequently filed a notice of appeal with the New York appellate court. In January 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York. The two derivative actions pending in federal district court in Ohio have been consolidated and the plaintiffs in the consolidated action filed an amended complaint. AEP filed a motion to dismiss the amended complaint and subsequently filed a brief in opposition to the New York plaintiffs' motion to intervene in the consolidated action in Ohio. In March 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. In April 2023, one of the plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Sixth Circuit of the Ohio federal district court order dismissing the consolidated action and denying the intervention. The defendants will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In March 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter was directed to the Board of Directors of AEP (AEP Board) and contained factual allegations involving HB 6 that were generally consistent with those in the derivative litigation filed in state and federal court. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect. In April 2023, AEP received a litigation demand from counsel representing the purported AEP shareholder who filed the dismissed derivative action in New York state court and unsuccessfully tried to intervene in the consolidated derivative actions in Ohio federal court. The litigation demand letter is directed to the AEP Board 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 certain current and former directors and officers, and that AEP commence a civil action for breaches of fiduciary duty and related claims against any individuals who allegedly harmed AEP. The AEP Board considered the 2023 litigation demand letter and formed a committee of the Board (the "Demand Review Committee") to investigate, review, monitor and analyze the allegations in the letter and make a recommendation to the

AEP Board regarding a reasonable and appropriate response to the same. 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 passage of HB 6 and documents relating to AEP's policies and financial processes and controls. In August 2022, AEP received a second subpoena from the SEC seeking various additional documents relating to its ongoing investigation. AEP is cooperating fully with the SEC's investigation, which has included taking testimony from certain individuals and inquiries regarding Empowering Ohio's Economy, Inc., which is a 501(c)(4) social welfare organization, and related disclosures. The SEC staff has advanced its discussions with certain parties involved in the investigation, including AEP, concerning the staff's intentions regarding potential claims under the securities laws. AEP and the SEC are engaged in discussions about a possible resolution of the SEC's investigation and potential claims under the securities laws. Any resolution or filed claims, the outcome of which cannot be predicted, may subject AEP to civil penalties and other remedial measures. Discussions are continuing and management is unable to determine a range of potential losses that is reasonably possible of occurring, but management does not believe the results of this investigation or a possible resolution thereof will have a material impact on results of operations, cash flows or financial condition.

Claims for Indemnification Made by Owners of the Gavin Power Station (Applies to AEP)

In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow a CCR surface impoundment at the Gavin Power Station to continue to receive CCR and non-CCR waste streams after April 11, 2021 until May 4, 2023 (the Gavin Denial). As part of the Gavin Denial, the Federal EPA made several assertions related to the CCR Rule (see "Environmental Issues - CCR Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information), including an assertion that the closure of the 300 acre unlined fly ash reservoir (FAR) is noncompliant with the CCR Rule in multiple respects. The Gavin Power Station was formerly owned and operated by AEP and was sold to Gavin Power LLC and Lightstone Generation LLC in 2017. Pursuant to the PSA, AEP maintained responsibility to complete closure of the FAR in accordance with the closure plan approved by the Ohio EPA which was completed in July 2021. The PSA contains indemnification provisions, pursuant to which the owners of the Gavin Power Station have notified AEP they believe they are entitled to indemnification for any damages that may result from these claims, including any future enforcement or litigation resulting from any determinations of noncompliance by the Federal EPA with various aspects of the CCR Rule consistent with the Gavin Denial. The owners of the Gavin Power Station have also sought indemnification for landowner claims for property damage allegedly caused by modifications to the FAR. Management does not believe that the owners of the Gavin Power Station have any valid claim for indemnity or otherwise against AEP under the PSA. In addition, Gavin Power LLC, several AEP subsidiaries, and other parties have filed Petitions for Review of the Gavin Denial with the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to determine a range of potential losses that is reasonably possible of occurring. Gavin Power LLC has also filed a complaint with the United States District Court for the Southern District of Ohio, alleging various violations of the Administrative Procedure Act and asserting that the Federal EPA, through its prior inaction, has waived and is estopped from raising certain objections raised in the Gavin Denial. Management cannot predict the outcome of that litigation.

7. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

Dry Lake Solar Project (Generation & Marketing Segment) (Applies to AEP)

In March 2021, AEP acquired a 75% ownership interest in the Dry Lake Solar Project located in southern Nevada for approximately $114 million and the project was placed in-service in May 2021. In August 2023, Dry Lake was included in the sale of the competitive contracted renewables portfolio. See the "Disposition of the Competitive Contracted Renewables Portfolio" section below and Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

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 1,484 MWs, on a fixed cost turn-key basis. PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. In total, the three wind facilities cost approximately $2 billion and consist of Traverse (998 MW), Maverick (287 MW) and Sundance (199 MW). Output from the NCWF serves 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 until the amounts are reflected in base rates. Recovery of the Arkansas portion of the NCWF revenue requirement through base rates was approved by the APSC in May 2022. 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. 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. Maverick was placed in-service in September 2021. In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction for $1.2 billion. Traverse was placed in-service in March 2022. Immediately following the acquisitions, PSO and SWEPCo liquidated the entities and simultaneously distributed the assets in proportion to their undivided ownership interests. PSO and SWEPCo apply the joint plant accounting model to account for their respective undivided interests in the assets, liabilities, revenues and expenses of the NCWF projects.

Rock Falls Wind Facility (Vertically Integrated Utilities Segment) (Applies to AEP and PSO)

In November 2022, PSO entered into an agreement to acquire the Rock Falls Wind Facility. In February 2023, the FERC approved PSO's acquisition of the Rock Falls Wind Facility under Section 203 of the Federal Power Act. In March 2023, PSO acquired an ownership interest in the entity that owned Rock Falls during its development and construction for $146 million. In accordance with the guidance for "Business Combinations," AEP management determined that the acquisition of the Rock Falls Wind Facility represents an asset acquisition. The lease obligations related to Rock Falls were not material at the time of acquisition. See the "2022 Oklahoma Base Rate Case" section of Note 4 for additional information.

DISPOSITIONS

Termination of Planned Disposition of KPCo and KTCo (Vertically Integrated Utilities and AEP Transmission Holdco Segments) (Applies to AEP and AEPTCo)

In October 2021, AEP entered into a Stock Purchase Agreement (SPA) 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 SPA was subsequently amended in September 2022 to reduce the purchase price to approximately $2.646 billion. The sale required approval from the KPSC and from the FERC under Section 203 of the Federal Power Act. The SPA contained certain termination rights if the closing of the sale did not occur by April 26, 2023.

In May 2022, the KPSC approved the sale of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. In December 2022, the FERC issued an order denying, without prejudice, authorization of the proposed sale stating the applicants failed to demonstrate the proposed transaction will not have an adverse effect on rates. In February 2023, a new filing for approval under Section 203 of the Federal Power Act was submitted. In March 2023, the KPSC and other intervenors made filings recommending the FERC reject AEP and Liberty's new Section 203 application seeking approval of the sale.

As a result of delays in the anticipated timing of the closing of the transaction and other factors, AEP recorded a $363 million pretax loss on the expected sale of the Kentucky Operations for the year ended December 31, 2022. In April 2023, AEP, AEPTCo and Liberty entered into a Mutual Termination Agreement (Termination Agreement) terminating the SPA. The parties entered into the Termination Agreement as all of the conditions precedent to closing the sale could not be satisfied prior to April 26, 2023. Upon termination of the sale and reverting to a held and used model, in the first quarter of 2023, AEP reversed $28 million of expected transaction costs included in the $363 million pretax loss and was required to present its investment in the Kentucky Operations at the lower of fair value or historical carrying value which resulted in a $335 million reduction recorded in Property, Plant and Equipment. The reduced investment in KPCo's assets is being amortized over the 30-year average useful life of the KPCo assets.

Disposition of the Competitive Contracted Renewables Portfolio (Generation & Marketing Segment) (Applies to AEP)

In February 2022, AEP management announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio (the portfolio) within the Generation & Marketing segment. In late January 2023, AEP received final bids from interested parties. In February 2023, AEP's Board of Directors approved management's plan to sell the portfolio and AEP signed an agreement with a nonaffiliated party.

In August 2023, AEP completed the sale of the entire portfolio to the nonaffiliated party and received cash proceeds of approximately $1.2 billion, net of taxes and transaction costs. AEP recorded a pretax loss of $93 million ($73 million after-tax) for the year ended December 31, 2023 related to the sale.

Disposition of Mineral Rights (Generation & Marketing Segment) (Applies to AEP)

In June 2022, AEP closed on the sale of certain mineral rights to a nonaffiliated third-party and received $120 million of proceeds. The sale resulted in a pretax gain of $116 million in the second quarter of 2022.

IMPAIRMENTS

2012 Texas Base Rate Case (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)

In December 2023, SWEPCo recorded a pretax, non-cash disallowance of $86 million in Asset Impairments and Other Related Charges on the statements of income due to regulatory disallowance of recovery of AFUDC on Turk Plant in the 2012 Texas Base Rate case. See the "2012 Texas Base Rate Case" section of Note 4 for additional information.

NMRD (Generation & Marketing Segment) (Applies to AEP)

In December 2023, as a result of sale negotiations AEP determined a decline in the fair value of AEP's investment in New Mexico Renewable Development (NMRD) was other than temporary. In accordance with the accounting guidance for "Investment - Equity Method and Joint Ventures", in the fourth quarter of 2023 AEP recorded a pretax other than temporary impairment charge of $19 million which is presented in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's Statement of Income. AEP's determination of fair value utilized the accounting guidance for Fair Value Measurement market approach to valuation and was based on negotiations to sell the investment to a non-affiliate. The carrying value of the investment in NMRD was not material to AEP as of December 31, 2023.

Flat Ridge 2 Wind LLC (Generation & Marketing Segment) (Applies to AEP)

In 2019, AEP acquired a 50% ownership interest in five non-consolidated joint ventures, including Flat Ridge 2 Wind LLC (Flat Ridge 2), and two tax equity partnerships. The five non-consolidated joint ventures are jointly owned and operated by BP Wind Energy. Flat Ridge 2 sells electricity to three counterparties through long-term PPAs.

Regarding AEP's investment in Flat Ridge 2, in June 2022, as a result of Flat Ridge 2's deteriorating financial performance, sale negotiations and AEP's ongoing evaluation and ultimate decision to exit the investment in the near term, AEP determined a decline in the fair value of AEP's investment in Flat Ridge 2 was other than temporary. In accordance with the accounting guidance for "Investments - Equity Method and Joint Ventures", in the second quarter of 2022 AEP recorded a pretax other than temporary impairment charge of $186 million which is presented in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's Statement of Income. AEP's determination of fair value utilized the accounting guidance for Fair Value Measurement market approach to valuation and was based on negotiations to sell the investment to a non-affiliate. In the third quarter of 2022, AEP recorded an additional $2 million pretax other than temporary impairment charge which is presented in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's Statement of Income. In September 2022, AEP signed a Purchase and Sale Agreement with a nonaffiliate for AEP's interest in Flat Ridge 2. The transaction closed in the fourth quarter of 2022 and had an immaterial impact on the financial statements at closing.

2020 Texas Base Rate Case (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)

In January 2022, the PUCT issued a final order which included a return of investment only for the recovery of the Dolet Hills Power Station. As a result of the final order, SWEPCo recorded a disallowance of $12 million associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging denial of a reasonable return or carrying costs on the Dolet Hills Power Station among other items. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order. See "2020 Texas Base Rate Case" section of Note 4 for additional information.

8. BENEFIT PLANS

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

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

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

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

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
Assumption	2023	2022	2023	2022
Discount Rate	5.15 %	5.50 %	5.15 %	5.50 %
Interest Crediting Rate	4.00 %	4.25 %	NA	NA

NA Not applicable.

Assumption – Rate of Compensation Increase (a) - Pension Plans

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
December 31, 2023	5.05 %	5.20 %	4.95 %	5.05 %	5.45 %	5.20 %	5.00 %
December 31, 2022	5.05 %	5.15 %	4.90 %	5.00 %	5.35 %	5.15 %	5.00 %

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

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

For 2023, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			OPEB		
	Year Ended December 31,					
Assumption	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Discount Rate	5.50 %	2.90 %	2.50 %	5.50 %	2.90 %	2.55 %
Interest Crediting Rate	4.25 %	4.00 %	4.00 %	NA	NA	NA
Expected Return on Plan Assets	7.50 %	5.25 %	4.75 %	7.25 %	5.50 %	4.75 %

NA Not applicable.

Assumption – Rate of Compensation Increase (a) - Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
December 31, 2023	5.05 %	5.20 %	4.95 %	5.05 %	5.45 %	5.20 %	5.00 %
December 31, 2022	5.05 %	5.15 %	4.90 %	5.00 %	5.35 %	5.15 %	5.00 %
December 31, 2021	5.10 %	5.10 %	4.85 %	5.00 %	5.30 %	5.10 %	4.95 %

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

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

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

Health Care Trend Rates	December 31, 2023	December 31, 2022
Initial	7.00 %	7.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2030	2029

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2023, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

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

For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual net benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. For the year ended December 31, 2022, the pension plans had an actuarial gain primarily due to an increase in the discount rate and was partially offset by increases in the assumed lump sum conversion rate and cash balance account interest crediting rate. For the year ended December 31, 2022, the OPEB plans had an actuarial gain primarily due to an increase in the discount rate and updated per capita cost assumptions. The OPEB plans gains were partially offset by a projected reduction in the Employer Group Waiver Program catastrophic reinsurance offset provided to AEP, resulting from the Inflation Reduction Act as well as an increase in the health care cost trend assumption. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

Pension Plans

2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Change in Benefit Obligation				(in millions)			
Benefit Obligation as of January 1,	$ 4,072.7	$ 334.1	$ 485.7	$ 466.8	$ 363.6	$ 192.3	$ 250.7
Service Cost	94.3	8.2	9.1	11.9	8.4	5.5	7.7
Interest Cost	219.2	18.3	26.4	24.9	19.8	10.7	13.9
Actuarial Loss	144.0	20.1	23.2	8.5	17.5	13.6	16.8
Benefit Payments	(368.6)	(37.6)	(40.3)	(35.1)	(30.9)	(19.9)	(27.9)
Benefit Obligation as of December 31,	$ 4,161.6	$ 343.1	$ 504.1	$ 477.0	$ 378.4	$ 202.2	$ 261.2
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 4,124.7	$ 335.1	$ 531.7	$ 533.7	$ 406.4	$ 218.5	$ 231.3
Actual Gain on Plan Assets	353.8	34.8	58.4	51.5	44.0	24.0	23.9
Company Contributions (a)	8.3	0.4	—	0.5	—	0.1	0.2
Benefit Payments	(368.6)	(37.6)	(40.3)	(35.1)	(30.9)	(19.9)	(27.9)
Fair Value of Plan Assets as of December 31,	$ 4,118.2	$ 332.7	$ 549.8	$ 550.6	$ 419.5	$ 222.7	$ 227.5
Funded (Underfunded) Status as of December 31,	$ (43.4)	$ (10.4)	$ 45.7	$ 73.6	$ 41.1	$ 20.5	$ (33.7)

2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Change in Benefit Obligation				(in millions)			
Benefit Obligation as of January 1,	$ 5,187.0	$ 419.8	$ 621.7	$ 612.1	$ 470.7	$ 252.6	$ 317.7
Service Cost	123.1	11.1	11.4	16.2	11.2	7.4	10.6
Interest Cost	148.2	12.1	17.5	17.0	13.3	7.0	9.1
Actuarial Gain	(983.4)	(67.8)	(123.1)	(138.0)	(97.9)	(52.9)	(57.9)
Benefit Payments	(402.2)	(41.1)	(41.8)	(40.5)	(33.7)	(21.8)	(28.8)
Benefit Obligation as of December 31,	$ 4,072.7	$ 334.1	$ 485.7	$ 466.8	$ 363.6	$ 192.3	$ 250.7
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 5,352.9	$ 444.9	$ 683.3	$ 681.5	$ 524.8	$ 286.2	$ 308.3
Actual (Loss) on Plan Assets	(833.7)	(69.2)	(109.8)	(107.4)	(84.8)	(46.0)	(48.3)
Company Contributions (a)	7.7	0.5	—	0.1	0.1	0.1	0.1
Benefit Payments	(402.2)	(41.1)	(41.8)	(40.5)	(33.7)	(21.8)	(28.8)
Fair Value of Plan Assets as of December 31,	$ 4,124.7	$ 335.1	$ 531.7	$ 533.7	$ 406.4	$ 218.5	$ 231.3
Funded (Underfunded) Status as of December 31,	$ 52.0	$ 1.0	$ 46.0	$ 66.9	$ 42.8	$ 26.2	$ (19.4)

(a) No contributions were made to the qualified pension plan for the years ended December 31, 2023 and 2022, respectively. Contributions to the non-qualified pension plans were $8 million and $8 million for the years ended December 31, 2023 and 2022, respectively.

OPEB

2023 Change in Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Benefit Obligation as of January 1,	$ 872.6	$ 68.6	$ 140.7	$ 101.9	$ 88.9	$ 45.7	$ 55.1
Service Cost	4.6	0.3	0.5	0.6	0.4	0.3	0.4
Interest Cost	46.2	3.6	7.4	5.4	4.7	2.4	2.9
Actuarial Loss	19.8	1.2	0.9	3.2	2.2	0.4	1.2
Benefit Payments	(137.8)	(10.7)	(21.6)	(18.3)	(15.0)	(7.6)	(8.8)
Participant Contributions	43.6	3.4	6.6	6.0	4.7	2.5	2.9
Medicare Subsidy	0.5	—	0.1	—	—	—	—
Benefit Obligation as of December 31,	$ 849.5	$ 66.4	$ 134.6	$ 98.8	$ 85.9	$ 43.7	$ 53.7
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 1,549.3	$ 128.3	$ 228.6	$ 190.5	$ 166.2	$ 85.4	$ 103.0
Actual Gain on Plan Assets	213.2	16.5	28.1	26.4	21.9	9.9	14.0
Company Contributions	5.0	—	1.3	—	—	—	—
Participant Contributions	43.6	3.4	6.6	6.0	4.7	2.5	2.9
Benefit Payments	(137.8)	(10.7)	(21.6)	(18.3)	(15.0)	(7.6)	(8.8)
Fair Value of Plan Assets as of December 31,	$ 1,673.3	$ 137.5	$ 243.0	$ 204.6	$ 177.8	$ 90.2	$ 111.1
Funded Status as of December 31,	$ 823.8	$ 71.1	$ 108.4	$ 105.8	$ 91.9	$ 46.5	$ 57.4

2022 Change in Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Benefit Obligation as of January 1,	$ 1,041.3	$ 80.5	$ 167.3	$ 118.6	$ 104.9	$ 54.4	$ 65.2
Service Cost	7.4	0.5	0.8	0.9	0.6	0.4	0.6
Interest Cost	29.2	2.2	4.7	3.4	3.0	1.5	1.8
Actuarial Gain	(109.8)	(7.1)	(16.2)	(8.7)	(8.9)	(5.2)	(6.6)
Benefit Payments	(140.1)	(10.9)	(23.0)	(18.3)	(15.5)	(7.9)	(8.8)
Participant Contributions	44.1	3.4	7.0	6.0	4.8	2.5	2.9
Medicare Subsidy	0.5	—	0.1	—	—	—	—
Benefit Obligation as of December 31,	$ 872.6	$ 68.6	$ 140.7	$ 101.9	$ 88.9	$ 45.7	$ 55.1
Change in Fair Value of Plan Assets							
Fair Value of Plan Assets as of January 1,	$ 2,044.3	$ 168.8	$ 302.3	$ 248.7	$ 220.0	$ 114.0	$ 136.6
Actual Loss on Plan Assets	(403.6)	(33.0)	(59.3)	(45.9)	(43.1)	(23.2)	(27.7)
Company Contributions	4.6	—	1.6	—	—	—	—
Participant Contributions	44.1	3.4	7.0	6.0	4.8	2.5	2.9
Benefit Payments	(140.1)	(10.9)	(23.0)	(18.3)	(15.5)	(7.9)	(8.8)
Fair Value of Plan Assets as of December 31,	$ 1,549.3	$ 128.3	$ 228.6	$ 190.5	$ 166.2	$ 85.4	$ 103.0
Funded Status as of December 31,	$ 676.7	$ 59.7	$ 87.9	$ 88.6	$ 77.3	$ 39.7	$ 47.9

Amounts Included on the Balance Sheets Related to Funded Status

Pension Plans

December 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ 17.3	$ 0.1	$ 46.0	$ 74.8	$ 41.4	$ 21.8	$ —
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.7)	(0.3)	—	—	—	(0.1)	(0.1)
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(54.0)	(10.2)	(0.3)	(1.2)	(0.3)	(1.2)	(33.6)
Funded (Underfunded) Status	$ (43.4)	$ (10.4)	$ 45.7	$ 73.6	$ 41.1	$ 20.5	$ (33.7)

December 31, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ 113.4	$ 3.7	$ 46.6	$ 68.5	$ 43.1	$ 27.6	$ —
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.3)	(0.4)	—	(0.1)	—	(0.1)	(0.1)
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(55.1)	(2.3)	(0.6)	(1.5)	(0.3)	(1.3)	(19.3)
Funded (Underfunded) Status	$ 52.0	$ 1.0	$ 46.0	$ 66.9	$ 42.8	$ 26.2	$ (19.4)

OPEB

December 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ 838.0	$ 71.1	$ 125.6	$ 105.8	$ 91.9	$ 46.5	$ 57.4
Other Current Liabilities – Accrued Short-term Benefit Liability	(2.4)	—	(1.6)	—	—	—	—
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(11.8)	—	(15.6)	—	—	—	—
Funded Status	$ 823.8	$ 71.1	$ 108.4	$ 105.8	$ 91.9	$ 46.5	$ 57.4

December 31, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Other Noncurrent Assets - Employee Benefits and Pension Assets	$ 699.5	$ 59.7	$ 106.3	$ 88.6	$ 77.3	$ 39.7	$ 47.9
Other Current Liabilities – Accrued Short-term Benefit Liability	(2.5)	—	(1.6)	—	—	—	—
Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(20.3)	—	(16.8)	—	—	—	—
Funded Status	$ 676.7	$ 59.7	$ 87.9	$ 88.6	$ 77.3	$ 39.7	$ 47.9

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

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

Pension Plans

December 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				(in millions)			
Net Actuarial (Gain) Loss	$ 1,063.4	$ 175.2	$ 104.9	$ (5.8)	$ 131.9	$ 46.7	$ 89.6
Prior Service Cost	0.2	—	—	—	—	—	—
Recorded as							
Regulatory Assets	$ 938.6	$ 163.4	$ 102.6	$ 6.4	$ 131.9	$ 46.7	$ 89.7
Deferred Income Taxes	26.4	2.7	0.4	(2.6)	—	—	—
Net of Tax AOCI	98.6	9.1	1.9	(9.6)	—	—	(0.1)

December 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				(in millions)			
Actuarial Loss During the Year	$ 129.2	$ 13.4	$ 9.3	$ 1.2	$ 7.6	$ 7.9	$ 12.1
Amortization of Actuarial Loss	(1.4)	(0.1)	—	(0.1)	—	—	(0.1)
Change for the Year Ended December 31,	$ 127.8	$ 13.3	$ 9.3	$ 1.1	$ 7.6	$ 7.9	$ 12.0

December 31, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				(in millions)			
Net Actuarial (Gain) Loss	$ 935.6	$ 161.9	$ 95.6	$ (6.9)	$ 124.3	$ 38.8	$ 77.6
Prior Service Cost	0.2	—	—	—	—	—	—
Recorded as							
Regulatory Assets	$ 841.8	$ 151.2	$ 93.6	$ 4.8	$ 124.3	$ 38.8	$ 77.6
Deferred Income Taxes	19.9	2.4	0.4	(2.4)	—	—	—
Net of Tax AOCI	74.1	8.3	1.6	(9.3)	—	—	—

December 31, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				(in millions)			
Actuarial Loss During the Year	$ 103.9	$ 22.4	$ 19.1	$ 1.8	$ 11.7	$ 6.7	$ 5.0
Amortization of Actuarial Loss	(63.0)	(5.2)	(7.4)	(7.1)	(5.5)	(2.9)	(3.8)
Change for the Year Ended December 31,	$ 40.9	$ 17.2	$ 11.7	$ (5.3)	$ 6.2	$ 3.8	$ 1.2

OPEB

December 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Net Actuarial Loss	$ 201.5	$ 22.1	$ 27.1	$ 28.7	$ 18.1	$ 17.5	$ 18.4
Prior Service Credit	(27.4)	(2.3)	(4.2)	(3.7)	(2.9)	(1.6)	(2.1)
Recorded as							
Regulatory Assets	$ 106.1	$ 19.8	$ 13.2	$ 19.0	$ 15.2	$ 15.9	$ 10.2
Deferred Income Taxes	14.3	—	2.0	1.3	—	—	1.3
Net of Tax AOCI	53.7	—	7.7	4.7	—	—	4.8

December 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Actuarial Gain During the Year	$ (83.7)	$ (6.4)	$ (11.1)	$ (9.6)	$ (7.9)	$ (3.7)	$ (5.6)
Amortization of Actuarial Loss	(14.8)	(1.2)	(2.3)	(1.9)	(1.6)	(0.8)	(1.0)
Amortization of Prior Service Credit	63.1	5.3	9.2	8.7	6.3	4.0	4.9
Change for the Year Ended December 31,	$ (35.4)	$ (2.3)	$ (4.2)	$ (2.8)	$ (3.2)	$ (0.5)	$ (1.7)

December 31, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Net Actuarial Loss	$ 300.0	$ 29.7	$ 40.5	$ 40.2	$ 27.6	$ 22.0	$ 25.0
Prior Service Credit	(90.5)	(7.6)	(13.4)	(12.4)	(9.2)	(5.6)	(7.0)
Recorded as							
Regulatory Assets	$ 126.0	$ 22.0	$ 14.7	$ 22.1	$ 18.4	$ 16.4	$ 11.2
Deferred Income Taxes	17.5	0.1	2.5	1.2	—	—	1.5
Net of Tax AOCI	66.0	—	9.9	4.5	—	—	5.3

December 31, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Components				**(in millions)**			
Actuarial Loss During the Year	$ 403.6	$ 34.9	$ 59.4	$ 50.9	$ 46.1	$ 24.1	$ 28.5
Amortization of Prior Service Credit	71.4	6.1	10.4	9.7	7.1	4.4	5.3
Change for the Year Ended December 31,	$ 475.0	$ 41.0	$ 69.8	$ 60.6	$ 53.2	$ 28.5	$ 33.8

Determination of Pension Expense

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

Pension and OPEB Assets

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

	Pension Plan		OPEB	
	December 31,			
Company	**2023**	**2022**	**2023**	**2022**
AEP Texas	8.1 %	8.1 %	8.2 %	8.3 %
APCo	13.4 %	12.9 %	14.5 %	14.8 %
I&M	13.4 %	12.9 %	12.2 %	12.3 %
OPCo	10.2 %	9.9 %	10.6 %	10.7 %
PSO	5.4 %	5.3 %	5.4 %	5.5 %
SWEPCo	5.5 %	5.6 %	6.6 %	6.6 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	**Level 1**	**Level 2**	**Level 3**	**Other**	**Total**	**Year End Allocation**
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

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

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 347.6	$ —	$ —	$ —	$ 347.6	8.4 %
International	398.4	—	—	—	398.4	9.7 %
Common Collective Trusts (b)	—	—	—	379.9	379.9	9.2 %
Subtotal – Equities	746.0	—	—	379.9	1,125.9	27.3 %
Fixed Income (a):						
United States Government and Agency Securities	(0.6)	1,071.4	—	—	1,070.8	26.0 %
Corporate Debt	—	891.7	—	—	891.7	21.6 %
Foreign Debt	—	140.2	—	—	140.2	3.4 %
State and Local Government	—	37.0	—	—	37.0	0.9 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(0.6)	2,141.1	—	—	2,140.5	51.9 %
Infrastructure (b)	—	—	—	109.2	109.2	2.6 %
Real Estate (b)	—	—	—	276.9	276.9	6.7 %
Alternative Investments (b)	—	—	—	319.7	319.7	7.8 %
Cash and Cash Equivalents (b)	—	64.9	—	58.3	123.2	3.0 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	29.3	29.3	0.7 %
Total	$ 745.4	$ 2,206.0	$ —	$ 1,173.3	$ 4,124.7	100.0 %

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

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 414.1	$ —	$ —	$ —	$ 414.1	26.7 %
International	265.0	—	—	—	265.0	17.1 %
Common Collective Trusts (a)	—	—	—	169.1	169.1	10.9 %
Subtotal – Equities	679.1	—	—	169.1	848.2	54.7 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	120.3	120.3	7.8 %
United States Government and Agency Securities	0.1	155.8	—	—	155.9	10.1 %
Corporate Debt	—	141.5	—	—	141.5	9.1 %
Foreign Debt	—	21.0	—	—	21.0	1.4 %
State and Local Government	62.9	7.8	—	—	70.7	4.6 %
Subtotal – Fixed Income	63.0	326.1	—	120.3	509.4	33.0 %
Trust Owned Life Insurance:						
International Equities	—	46.7	—	—	46.7	3.0 %
United States Bonds	—	110.3	—	—	110.3	7.1 %
Subtotal – Trust Owned Life Insurance	—	157.0	—	—	157.0	10.1 %
Cash and Cash Equivalents (a)	23.2	—	—	6.7	29.9	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	4.8	4.8	0.3 %
Total	$ 765.3	$ 483.1	$ —	$ 300.9	$ 1,549.3	100.0 %

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

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 3,878.7	$ 321.1	$ 485.6	$ 450.3	$ 354.0	$ 186.6	$ 241.9
Nonqualified Pension Plans	54.8	2.1	0.1	0.7	0.1	1.2	1.0
Total as of December 31, 2023	$ 3,933.5	$ 323.2	$ 485.7	$ 451.0	$ 354.1	$ 187.8	$ 242.9

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 3,827.4	$ 315.4	$ 470.1	$ 443.8	$ 344.1	$ 179.1	$ 234.0
Nonqualified Pension Plans	55.6	2.5	0.3	1.2	0.1	1.2	1.1
Total as of December 31, 2022	$ 3,883.0	$ 317.9	$ 470.4	$ 445.0	$ 344.2	$ 180.3	$ 235.1

Obligations in Excess of Fair Values

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

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Projected Benefit Obligation	$ 60.7	$ 343.1	$ 0.4	$ 1.2	$ 0.3	$ 1.4	$ 261.2
Fair Value of Plan Assets	—	332.7	—	—	—	—	227.5
Underfunded Projected Benefit Obligation as of December 31, 2023	$ (60.7)	$ (10.4)	$ (0.4)	$ (1.2)	$ (0.3)	$ (1.4)	$ (33.7)

	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Projected Benefit Obligation	$ 61.5	$ 2.7	$ 0.6	$ 1.6	$ 0.3	$ 1.5	$ 250.7
Fair Value of Plan Assets	—	—	—	—	—	—	231.3
Underfunded Projected Benefit Obligation as of December 31, 2022	$ (61.5)	$ (2.7)	$ (0.6)	$ (1.6)	$ (0.3)	$ (1.5)	$ (19.4)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Accumulated Benefit Obligation	$ 54.8	$ 2.1	$ 0.1	$ 0.7	$ 0.1	$ 1.2	$ 242.9
Fair Value of Plan Assets	—	—	—	—	—	—	227.5
Underfunded Accumulated Benefit Obligation as of December 31, 2023	$ (54.8)	$ (2.1)	$ (0.1)	$ (0.7)	$ (0.1)	$ (1.2)	$ (15.4)

	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Accumulated Benefit Obligation	$ 55.6	$ 2.5	$ 0.3	$ 1.2	$ 0.1	$ 1.2	$ 235.1
Fair Value of Plan Assets	—	—	—	—	—	—	231.3
Underfunded Accumulated Benefit Obligation as of December 31, 2022	$ (55.6)	$ (2.5)	$ (0.3)	$ (1.2)	$ (0.1)	$ (1.2)	$ (3.8)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded non-qualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2024:

	AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Pension Plans	$ 6.7	$ 0.3	$ —	$ —	$ —	$ 0.1	$ 0.1
OPEB	3.0	—	1.6	—	—	—	—

The tables below reflect the total benefits expected to be paid from the plan or from the Registrants' assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2024	$ 369.5	$ 36.7	$ 43.9	$ 39.0	$ 32.6	$ 19.7	$ 24.4
2025	361.8	34.3	43.3	39.7	32.7	19.2	25.8
2026	365.7	34.5	44.1	39.7	32.5	19.4	26.1
2027	361.9	32.2	42.6	39.8	32.4	19.3	25.3
2028	357.8	32.2	43.5	39.4	31.3	19.0	23.7
Years 2029 to 2033, in Total	1,657.6	133.5	200.0	189.4	144.5	81.0	105.6

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2024	$ 117.2	$ 9.4	$ 18.8	$ 15.2	$ 12.6	$ 6.7	$ 7.8
2025	122.6	10.0	19.4	15.7	13.0	7.1	8.3
2026	122.4	10.2	19.3	15.7	12.8	7.0	8.3
2027	121.5	10.2	19.1	15.4	12.7	6.8	8.1
2028	120.2	9.9	19.0	15.0	12.5	6.5	8.2
Years 2029 to 2033, in Total	566.1	45.2	88.3	69.7	57.6	30.2	38.8

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2024	$ 0.3	$ —	$ 0.1	$ —	$ —	$ —	$ —
2025	0.3	—	0.1	—	—	—	—
2026	0.3	—	0.1	—	—	—	—
2027	0.3	—	0.1	—	—	—	—
2028	0.3	—	0.1	—	—	—	—
Years 2029 to 2033, in Total	1.5	—	0.5	—	—	—	—

Components of Net Periodic Benefit Cost

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

Pension Plans

2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 94.3	$ 8.2	$ 9.1	$ 11.9	$ 8.4	$ 5.5	$ 7.7
Interest Cost	219.2	18.3	26.4	24.9	19.8	10.7	13.9
Expected Return on Plan Assets	(339.2)	(28.1)	(44.6)	(44.2)	(34.0)	(18.3)	(19.4)
Amortization of Net Actuarial Loss	1.4	0.1	—	0.1	—	—	0.1
Net Periodic Benefit Cost (Credit)	(24.3)	(1.5)	(9.1)	(7.3)	(5.8)	(2.1)	2.3
Capitalized Portion	(43.6)	(4.7)	(4.2)	(3.6)	(4.7)	(2.5)	(3.0)
Net Periodic Benefit Credit Recognized in Expense	$ (67.9)	$ (6.2)	$ (13.3)	$ (10.9)	$ (10.5)	$ (4.6)	$ (0.7)

2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 123.1	$ 11.1	$ 11.4	$ 16.2	$ 11.2	$ 7.4	$ 10.6
Interest Cost	148.2	12.1	17.5	17.0	13.3	7.0	9.1
Expected Return on Plan Assets	(253.4)	(21.0)	(32.3)	(32.4)	(24.8)	(13.4)	(14.6)
Amortization of Net Actuarial Loss	63.0	5.2	7.4	7.1	5.5	2.9	3.8
Net Periodic Benefit Cost	80.9	7.4	4.0	7.9	5.2	3.9	8.9
Capitalized Portion	(53.8)	(6.2)	(5.0)	(4.6)	(6.1)	(3.2)	(4.0)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 27.1	$ 1.2	$ (1.0)	$ 3.3	$ (0.9)	$ 0.7	$ 4.9

2021	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 129.2	$ 11.8	$ 11.9	$ 17.5	$ 11.4	$ 8.0	$ 11.2
Interest Cost	137.2	11.2	16.4	16.2	12.5	6.7	8.5
Expected Return on Plan Assets	(229.7)	(19.5)	(29.1)	(28.9)	(22.3)	(12.3)	(13.5)
Amortization of Net Actuarial Loss	101.5	8.3	12.0	11.7	9.1	4.9	6.2
Net Periodic Benefit Cost	138.2	11.8	11.2	16.5	10.7	7.3	12.4
Capitalized Portion	(55.7)	(6.6)	(5.2)	(4.9)	(6.2)	(3.4)	(4.1)
Net Periodic Benefit Cost Recognized in Expense	$ 82.5	$ 5.2	$ 6.0	$ 11.6	$ 4.5	$ 3.9	$ 8.3

OPEB

2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 4.6	$ 0.3	$ 0.5	$ 0.6	$ 0.4	$ 0.3	$ 0.4
Interest Cost	46.2	3.6	7.4	5.4	4.7	2.4	2.9
Expected Return on Plan Assets	(109.6)	(9.0)	(16.1)	(13.5)	(11.8)	(5.9)	(7.2)
Amortization of Prior Service Credit	(63.1)	(5.3)	(9.2)	(8.7)	(6.3)	(4.0)	(4.9)
Amortization of Net Actuarial Loss	14.8	1.2	2.3	1.9	1.6	0.8	1.0
Net Periodic Benefit Credit	(107.1)	(9.2)	(15.1)	(14.3)	(11.4)	(6.4)	(7.8)
Capitalized Portion	(2.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.2)
Net Periodic Benefit Credit Recognized in Expense	$ (109.2)	$ (9.4)	$ (15.3)	$ (14.5)	$ (11.6)	$ (6.5)	$ (8.0)

2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 7.4	$ 0.5	$ 0.8	$ 0.9	$ 0.6	$ 0.4	$ 0.6
Interest Cost	29.2	2.2	4.7	3.4	3.0	1.5	1.8
Expected Return on Plan Assets	(110.0)	(9.1)	(16.3)	(13.7)	(12.0)	(6.1)	(7.3)
Amortization of Prior Service Credit	(71.4)	(6.1)	(10.4)	(9.7)	(7.1)	(4.4)	(5.3)
Net Periodic Benefit Credit	(144.8)	(12.5)	(21.2)	(19.1)	(15.5)	(8.6)	(10.2)
Capitalized Portion	(3.2)	(0.3)	(0.4)	(0.3)	(0.3)	(0.2)	(0.2)
Net Periodic Benefit Credit Recognized in Expense	$ (148.0)	$ (12.8)	$ (21.6)	$ (19.4)	$ (15.8)	$ (8.8)	$ (10.4)

2021	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 9.5	$ 0.7	$ 1.0	$ 1.3	$ 0.8	$ 0.6	$ 0.8
Interest Cost	30.5	2.4	4.9	3.5	3.0	1.6	1.9
Expected Return on Plan Assets	(91.1)	(7.5)	(13.5)	(11.1)	(9.7)	(5.0)	(6.1)
Amortization of Prior Service Credit	(70.9)	(6.0)	(10.3)	(9.6)	(7.2)	(4.4)	(5.3)
Net Periodic Benefit Credit	(122.0)	(10.4)	(17.9)	(15.9)	(13.1)	(7.2)	(8.7)
Capitalized Portion	(4.1)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)
Net Periodic Benefit Credit Recognized in Expense	$ (126.1)	$ (10.8)	$ (18.3)	$ (16.3)	$ (13.5)	$ (7.5)	$ (9.0)

American Electric Power System Retirement Savings Plan

AEPSC sponsors the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all AEP subsidiary employees who are not covered by a retirement savings plan of the UMWA. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant:

Year Ended December 31,	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2023	$ 87.9	$ 7.1	$ 8.4	$ 11.0	$ 8.2	$ 5.3	$ 6.7
2022	81.9	6.5	7.8	11.1	7.7	4.7	6.4
2021	79.9	6.4	7.6	10.9	7.2	4.6	6.4

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits negotiated with the UMWA for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan is in Critical Status for the plan year beginning July 1, 2023 and was in Critical Status for the plan year beginning July 1, 2022. As required under the PPA, the Plan adopted a Rehabilitation Plan in 2015. The Rehabilitation Plan has been updated annually, most recently in April 2023.

AEP affiliates contributed $396 thousand, $329 thousand and $339 thousand to the United Mine Workers of America 1974 Pension Plan for the years ended December 31, 2023, 2022 and 2021, respectively. The contributions did not include surcharges. An AEP affiliate, Cook Coal Terminal (CCT), was listed in the plan's 2021 Form 5500 as providing more than 5 percent of the total contributions for the plan year ending June 30, 2022. The plan's 2022 Form 5500 is expected to be filed in the second quarter of 2024.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the January 25, 2025 expiration of the current collective bargaining agreement between the CCT facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

AEP records a UMWA pension withdrawal liability on the balance sheet that is re-measured annually and is the estimated value of the company's anticipated contributions toward its proportionate share of the plan's unfunded vested liabilities. As of December 31, 2023 and 2022, the liability balance was $13 million and $12 million, respectively. AEP recovers the estimated value of its UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity 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 energy 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, income tax expense and other nonallocated costs.

AEP's Chief Operating Decision Maker makes operating decisions, allocates resources to and assesses performance based on these operating segments. AEP measures segment profit or loss based on net income (loss). Net income (loss) includes intercompany revenues and expenses that are eliminated on the Consolidated Financial Statements. In addition, direct interest expense and income taxes are included in net income (loss).

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2023, 2022 and 2021 and reportable segment balance sheet information as of December 31, 2023 and 2022.

2023	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	$ 11,303.7	$ 5,677.2	$ 397.4	$ 1,543.3	$ 60.7	$ —	$ 18,982.3
Other Operating Segments	145.8	36.1	1,331.1	88.9	107.3	(1,709.2) (b)	—
Total Revenues	$ 11,449.5	$ 5,713.3	$ 1,728.5	$ 1,632.2	$ 168.0	$ (1,709.2)	$ 18,982.3
Asset Impairments and Other Related Charges	$ 85.6	$ —	$ —	$ —	$ —	$ —	$ 85.6
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	—	—	92.7	—	—	92.7
Depreciation and Amortization	1,876.4	784.7	402.6	42.7	(16.0)	—	3,090.4
Interest Expense	764.5	363.6	202.6	76.0	594.7	(194.5)	1,806.9
Income Tax Expense (Benefit)	(45.2)	140.2	166.0	(122.9)	(83.5)	—	54.6
Equity Earnings (Loss) of Unconsolidated Subsidiaries	1.4	—	82.9	(16.5)	(9.3)	—	58.5
Net Income (Loss)	$ 1,093.9	$ 698.7	$ 706.7	$ (29.1)	$ (257.6)	$ —	$ 2,212.6
Gross Property Additions	$ 3,486.8	$ 2,467.4	$ 1,528.7	$ 12.6	$ 36.6	$ 1.4	$ 7,533.5
Total Assets	$ 51,802.1	$ 24,838.4	$ 16,575.6	$ 2,598.5	$ 5,194.0 (c)	$ (4,324.6) (d)	$ 96,684.0
Investments in Equity Method Investees	$ 10.0	$ 3.0	$ 905.8	$ 100.6	$ 54.2	$ —	$ 1,073.6

2022	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	$ 11,292.8	$ 5,489.6	$ 357.5	$ 2,448.9	$ 50.7	$ —	$ 19,639.5
Other Operating Segments	184.7	22.4	1,319.5	18.0	59.2	(1,603.8) (b)	—
Total Revenues	$ 11,477.5	$ 5,512.0	$ 1,677.0	$ 2,466.9	$ 109.9	$ (1,603.8)	$ 19,639.5
Loss on the Expected Sale of the Kentucky Operations	$ —	$ —	$ —	$ —	$ 363.3	$ —	$ 363.3
Asset Impairments and Other Related Charges	24.9	—	—	—	23.9	—	48.8
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	—	—	—	—	(37.0)
Gain on Sale of Mineral Rights	—	—	—	(116.3)	—	—	(116.3)
Depreciation and Amortization	2,007.2	746.7	355.0	93.0	0.9	—	3,202.8
Interest Expense	650.9	328.0	169.3	51.8	308.9	(112.8)	1,396.1
Income Tax Expense (Benefit)	(93.8)	116.9	193.6	(83.1)	(128.2)	—	5.4
Equity Earnings (Loss) of Unconsolidated Subsidiaries	1.4	0.6	83.4	(192.4)	(2.4)	—	(109.4)
Net Income (Loss)	$ 1,296.2	$ 595.7	$ 676.8	$ 274.5	$ (537.6)	$ —	$ 2,305.6
Gross Property Additions	$ 4,164.6	$ 2,177.3	$ 1,470.8	$ 69.2	$ 25.9	$ (28.8)	$ 7,879.0
Total Assets	$ 49,761.8	$ 22,920.2	$ 15,215.8	$ 4,520.1	$ 6,768.4 (c)	$ (5,783.0) (d)	$ 93,403.3
Investments in Equity Method Investees	$ 10.1	$ 3.0	$ 858.3	$ 337.6	$ 67.7	$ —	$ 1,276.7

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	$ 9,852.2	$ 4,464.1	$ 351.1	$ 2,108.3	$ 16.3	$ —	$ 16,792.0
Other Operating Segments	146.3	28.8	1,175.1	55.4	55.9	(1,461.5) (b)	—
Total Revenues	$ 9,998.5	$ 4,492.9	$ 1,526.2	$ 2,163.7	$ 72.2	$ (1,461.5)	$ 16,792.0
Asset Impairments and Other Related Charges	$ 11.6	$ —	$ —	$ —	$ —	$ —	$ 11.6
Depreciation and Amortization	1,747.6	690.3	306.0	80.9	0.9	—	2,825.7
Interest Expense	574.2	300.9	146.3	15.6	180.8	(18.7)	1,199.1
Income Tax Expense (Benefit)	(11.2)	77.5	159.6	(48.8)	(61.6)	—	115.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries	3.4	—	75.0	(10.6)	23.9	—	91.7
Net Income (Loss)	$ 1,116.7	$ 543.4	$ 682.0	$ 210.2	$ (64.2)	$ —	$ 2,488.1
Gross Property Additions	$ 2,963.1	$ 1,766.0	$ 1,468.6	$ 232.8	$ 25.5	$ (29.2)	$ 6,426.8
Investments in Equity Method Investees	$ 33.5	$ 2.5	$ 830.4	$ 487.8	$ 93.3	$ —	$ 1,447.5

(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) Represents inter-segment revenues.
(c) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.

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

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

AEPTCo's Reportable Segments

AEPTCo Parent is the holding company of seven FERC-regulated transmission-only electric utilities. 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 years ended December 31, 2023, 2022 and 2021 and reportable segment balance sheet information as of December 31, 2023 and 2022.

2023	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 354.2	$ —	$ —	$ 354.2
Sales to AEP Affiliates	1,317.8	—	—	1,317.8
Total Revenues	$ 1,672.0	$ —	$ —	$ 1,672.0
Depreciation and Amortization	$ 393.8	$ —	$ —	$ 393.8
Interest Income	3.8	218.0	(214.8) (a)	7.0
Allowance for Equity Funds Used During Construction	83.2	—	—	83.2
Interest Expense	194.2	215.1	(214.8) (a)	194.5
Income Tax Expense	145.7	1.4	—	147.1
Net Income	$ 612.9	$ 1.3 (b)	$ —	$ 614.2
Gross Property Additions	$ 1,503.1	$ —	$ —	$ 1,503.1
Total Assets	$ 15,120.6	$ 5,486.6 (c)	$ (5,534.7) (d)	$ 15,072.5

2022	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 340.9	$ —	$ —	$ 340.9
Sales to AEP Affiliates	1,283.8	—	—	1,283.8
Other Revenues	(0.2)	—	—	(0.2)
Total Revenues	$ 1,624.5	$ —	$ —	$ 1,624.5
Depreciation and Amortization	$ 346.2	$ —	$ —	$ 346.2
Interest Income	0.7	177.8	(176.9) (a)	1.6
Allowance for Equity Funds Used During Construction	70.7	—	—	70.7
Interest Expense	162.5	177.1	(176.9) (a)	162.7
Income Tax Expense	169.1	—	—	169.1
Net Income	$ 594.2	$ — (b)	$ —	$ 594.2
Gross Property Additions	$ 1,468.3	$ —	$ —	$ 1,468.3
Total Assets	$ 13,875.6	$ 4,817.4 (c)	$ (4,878.8) (d)	$ 13,814.2

2021	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 315.1	$ —	$ —	$ 315.1
Sales to AEP Affiliates	1,153.9	—	—	1,153.9
Other Revenues	0.3	—	—	0.3
Total Revenues	$ 1,469.3	$ —	$ —	$ 1,469.3
Depreciation and Amortization	$ 297.3	$ —	$ —	$ 297.3
Interest Income	0.1	158.1	(157.7) (a)	0.5
Allowance for Equity Funds Used During Construction	67.2	—	—	67.2
Interest Expense	141.2	157.7	(157.7) (a)	141.2
Income Tax Expense	144.1	—	—	144.1
Net Income	$ 591.5	$ 0.2 (b)	$ —	$ 591.7
Gross Property Additions	$ 1,442.7	$ —	$ —	$ 1,442.7

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

10. DERIVATIVES AND HEDGING

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

The following table represents the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments

Primary Risk Exposure	December 31, 2023							December 31, 2022						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)													
Commodity:														
Power (MWhs)	246.8	—	16.8	5.9	2.2	4.1	2.9	226.8	—	17.9	4.2	2.5	2.9	2.2
Natural Gas (MMBtus)	151.6	—	37.3	—	—	34.9	17.9	77.1	—	1.9	—	—	1.9	2.1
Heating Oil and Gasoline (Gallons)	6.5	1.8	1.0	0.6	1.2	0.7	0.9	6.9	1.9	1.0	0.7	1.4	0.9	1.0
Interest Rate (USD)	$ 80.1	$ —	$ —	$ —	$ —	$ —	$ —	$ 99.9	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt (USD)	$1,300.0	$150.0	$ —	$ —	$ —	$ —	$ —	$1,650.0	$ —	$ —	$ —	$ —	$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. AEP netted cash collateral received from third-parties against short-term and long-term risk management assets in the amounts of $46 million and $481 million as of December 31, 2023 and 2022, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for the Registrant Subsidiaries as of December 31, 2023 and 2022. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for the Registrants as of December 31, 2023 and 2022.

Location and Fair Value of Derivative Assets and Liabilities Recognized In the Balance Sheet

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets. The derivative instruments are disclosed as gross. They 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." Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	December 31, 2023						
	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Assets:	(in millions)						
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 555.1	$ —	$ 24.6	$ 30.1	$ —	$ 19.7	$ 12.0
Hedging Contracts - Commodity	56.7	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Current Risk Management Assets	611.8	—	24.6	30.1	—	19.7	12.0
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	468.8	—	0.3	12.0	—	—	0.5
Hedging Contracts - Commodity	86.8	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Long-term Risk Management Assets	555.6	—	0.3	12.0	—	—	0.5
Total Assets	$ 1,167.4	$ —	$ 24.9	$ 42.1	$ —	$ 19.7	$ 12.5
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 588.0	$ 0.2	$ 18.5	$ 5.4	$ 6.9	$ 29.7	$ 14.9
Hedging Contracts - Commodity	8.2	—	—	—	—	—	—
Hedging Contracts - Interest Rate	50.5	2.7	—	—	—	—	—
Total Current Risk Management Liabilities	646.7	2.9	18.5	5.4	6.9	29.7	14.9
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	377.6	—	6.9	0.2	43.9	1.0	1.7
Hedging Contracts - Commodity	2.2	—	—	—	—	—	—
Hedging Contracts - Interest Rate	56.9	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	436.7	—	6.9	0.2	43.9	1.0	1.7
Total Liabilities	$ 1,083.4	$ 2.9	$ 25.4	$ 5.6	$ 50.8	$ 30.7	$ 16.6
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 84.0	$ (2.9)	$ (0.5)	$ 36.5	$ (50.8)	$ (11.0)	$ (4.1)

	December 31, 2022						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 965.4	$ —	$ 69.3	$ 16.0	$ —	$ 24.1	$ 16.8
Hedging Contracts - Commodity	212.2	—	—	—	—	—	—
Hedging Contracts - Interest Rate	1.8	—	—	—	—	1.6	—
Total Current Risk Management Assets	1,179.4	—	69.3	16.0	—	25.7	16.8
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	565.6	—	0.7	0.5	—	—	—
Hedging Contracts - Commodity	148.9	—	—	—	—	—	—
Hedging Contracts - Interest Rate	14.3	—	—	—	—	—	—
Total Long-term Risk Management Assets	728.8	—	0.7	0.5	—	—	—
Total Assets	$ 1,908.2	$ —	$ 70.0	$ 16.5	$ —	$ 25.7	$ 16.8
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 663.8	$ —	$ 4.1	$ 0.9	$ 2.1	$ 2.1	$ 2.0
Hedging Contracts - Commodity	60.4	—	—	—	—	—	—
Hedging Contracts - Interest Rate	41.4	—	—	—	—	—	—
Total Current Risk Management Liabilities	765.6	—	4.1	0.9	2.1	2.1	2.0
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	412.0	—	0.7	0.3	37.9	—	—
Hedging Contracts - Commodity	17.4	—	—	—	—	—	—
Hedging Contracts - Interest Rate	91.1	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	520.5	—	0.7	0.3	37.9	—	—
Total Liabilities	$ 1,286.1	$ —	$ 4.8	$ 1.2	$ 40.0	$ 2.1	$ 2.0
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 622.1	$ —	$ 65.2	$ 15.3	$ (40.0)	$ 23.6	$ 14.8

Offsetting Assets and Liabilities

The following tables show the net amounts of assets and liabilities presented on the balance sheets. The gross amounts offset include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with accounting guidance for "Derivatives and Hedging." All derivative contracts subject to a master netting arrangement or similar agreement are offset on the balance sheets.

	December 31, 2023						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Assets:							
Current Risk Management Assets							
Gross Amounts Recognized	$ 611.8	$ —	$ 24.6	$ 30.1	$ —	$ 19.7	$ 12.0
Gross Amounts Offset	(394.3)	—	(2.2)	(2.3)	—	(0.7)	(0.4)
Net Amounts Presented	217.5	—	22.4	27.8	—	19.0	11.6
Long-term Risk Management Assets							
Gross Amounts Recognized	555.6	—	0.3	12.0	—	—	0.5
Gross Amounts Offset	(234.4)	—	(0.3)	(0.2)	—	—	(0.5)
Net Amounts Presented	321.2	—	—	11.8	—	—	—
Total Assets	$ 538.7	$ —	$ 22.4	$ 39.6	$ —	$ 19.0	$ 11.6
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 646.7	$ 2.9	$ 18.5	$ 5.4	$ 6.9	$ 29.7	$ 14.9
Gross Amounts Offset	(417.1)	(0.2)	(2.6)	(3.4)	(0.1)	(0.8)	(0.5)
Net Amounts Presented	229.6	2.7	15.9	2.0	6.8	28.9	14.4
Long-term Risk Management Liabilities							
Gross Amounts Recognized	436.7	—	6.9	0.2	43.9	1.0	1.7
Gross Amounts Offset	(194.9)	—	(0.3)	(0.2)	—	—	(0.5)
Net Amounts Presented	241.8	—	6.6	—	43.9	1.0	1.2
Total Liabilities	$ 471.4	$ 2.7	$ 22.5	$ 2.0	$ 50.7	$ 29.9	$ 15.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 67.3	$ (2.7)	$ (0.1)	$ 37.6	$ (50.7)	$ (10.9)	$ (4.0)

	December 31, 2022						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Assets:							
Current Risk Management Assets							
Gross Amounts Recognized	$ 1,179.4	$ —	$ 69.3	$ 16.0	$ —	$ 25.7	$ 16.8
Gross Amounts Offset	(830.6)	—	(0.2)	(0.8)	—	(0.4)	(0.4)
Net Amounts Presented	348.8	—	69.1	15.2	—	25.3	16.4
Long-term Risk Management Assets							
Gross Amounts Recognized	728.8	—	0.7	0.5	—	—	—
Gross Amounts Offset	(444.7)	—	(0.7)	(0.3)	—	—	—
Net Amounts Presented	284.1	—	—	0.2	—	—	—
Total Assets	$ 632.9	$ —	$ 69.1	$ 15.4	$ —	$ 25.3	$ 16.4
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 765.6	$ —	$ 4.1	$ 0.9	$ 2.1	$ 2.1	$ 2.0
Gross Amounts Offset	(620.4)	—	(0.5)	(0.9)	(0.3)	(0.5)	(0.6)
Net Amounts Presented	145.2	—	3.6	—	1.8	1.6	1.4
Long-term Risk Management Liabilities							
Gross Amounts Recognized	520.5	—	0.7	0.3	37.9	—	—
Gross Amounts Offset	(175.3)	—	(0.6)	(0.3)	—	—	—
Net Amounts Presented	345.2	—	0.1	—	37.9	—	—
Total Liabilities	$ 490.4	$ —	$ 3.7	$ —	$ 39.7	$ 1.6	$ 1.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 142.5	$ —	$ 65.4	$ 15.4	$ (39.7)	$ 23.7	$ 15.0

The tables below present the Registrants' amount of gain (loss) recognized on risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Year Ended December 31, 2023						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ 24.6	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(423.8)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	24.5	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2.5	—	2.3	0.1	—	—	—
Other Operation	(0.2)	(0.1)	—	—	—	—	—
Maintenance	(0.8)	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)
Regulatory Assets (a)	(94.8)	(0.2)	(21.9)	(3.1)	(14.0)	(29.8)	(15.5)
Regulatory Liabilities (a)	169.7	—	1.0	7.8	—	88.7	70.7
Total Gain (Loss) on Risk Management Contracts	$ (322.8)	$ (0.6)	$ (18.6)	$ 29.2	$ (14.1)	$ 58.8	$ 55.0

	Year Ended December 31, 2022						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ 11.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	313.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.5	10.6	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	5.0	—	4.5	0.1	—	0.2	—
Other Operation	4.8	1.5	0.4	0.5	0.8	0.6	0.8
Maintenance	6.7	1.8	0.9	0.6	1.2	0.8	1.1
Regulatory Assets (a)	52.6	0.1	(0.1)	(0.8)	52.1	3.6	(2.1)
Regulatory Liabilities (a)	299.7	(0.6)	82.4	8.6	3.7	98.5	77.9
Total Gain on Risk Management Contracts	$ 693.7	$ 2.8	$ 88.6	$ 19.6	$ 57.8	$ 103.7	$ 77.7

	Year Ended December 31, 2021						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (0.6)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	169.1	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.5)	(0.1)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2.0	—	1.8	—	—	—	—
Other Operation	2.8	0.8	0.3	0.3	0.5	0.3	0.4
Maintenance	3.4	1.0	0.5	0.3	0.6	0.4	0.5
Regulatory Assets (a)	(9.1)	—	(2.7)	(14.8)	10.0	(3.6)	3.6
Regulatory Liabilities (a)	156.4	0.2	55.9	(3.9)	—	48.9	37.0
Total Gain (Loss) on Risk Management Contracts	$ 324.0	$ 2.0	$ 55.3	$ (18.2)	$ 11.1	$ 46.0	$ 41.5

(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	
	December 31, 2023	**December 31, 2022**	**December 31, 2023**	**December 31, 2022**
		(in millions)		
Long-term Debt (a) (b)	$ (878.2)	$ (855.5)	$ 68.4	$ 89.7

(a) Amounts included within Noncurrent Liabilities line item Long-term Debt on the Balance Sheet.
(b) Amounts include $(30) million and $(38) million as of December 31, 2023 and 2022, 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:

	Years Ended December 31,		
	2023	**2022**	**2021**
		(in millions)	
Gain (Loss) on Interest Rate Contracts:			
Fair Value Hedging Instruments (a)	$ 29.0	$ (90.4)	$ (35.5)
Fair Value Portion of Long-term Debt (a)	(29.0)	90.4	35.5

(a) Gain (Loss) is included in Interest Expense on the statements of income.

Accounting for Cash Flow Hedging Strategies (Applies to AEP, AEP Texas, APCo, I&M, PSO and SWEPCo)

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, Fuel and Other Consumables Used for Electric Generation on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2023, 2022 and 2021, 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 year ended 2023, AEP, AEP Texas, I&M, PSO and SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the year ended 2022, AEP and PSO applied cash flow hedging to outstanding interest rate derivatives. During the year ended 2021, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3 - Comprehensive Income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on the Registrants' Balance Sheets

	December 31, 2023				December 31, 2022			
	AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months		AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months	
	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)							
AEP	$ 104.9	$ (8.1)	$ 38.3	$ 3.2	$ 223.5	$ 0.3	$ 119.9	$ 0.3
AEP Texas	—	0.5	—	0.2	—	(0.3)	—	(0.2)
APCo	—	5.9	—	0.8	—	6.7	—	0.8
I&M	—	(5.5)	—	(0.4)	—	(5.1)	—	(0.6)
PSO	—	(0.2)	—	—	—	1.3	—	0.1
SWEPCo	—	1.3	—	0.3	—	1.1	—	0.2

As of December 31, 2023 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 87 months.

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.

Credit-Risk-Related Contingent Features

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 with a total exposure of $0 and $2 million as of December 31, 2023 and 2022, respectively. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2023 and 2022.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by the Registrants under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. AEP had derivative contracts with cross-acceleration provisions in a net liability position of $107 million and $127 million and no cash collateral posted as of December 31, 2023 and 2022, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries' derivative contracts with cross-acceleration provisions outstanding as of December 31, 2023 and 2022 were not material.

Cross-Default Triggers (Applies to AEP, APCo, I&M, PSO 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. AEP had derivative contracts with cross-default provisions in a net liability position of $242 million and $217 million and no cash collateral posted as of December 31, 2023 and 2022, respectively, after considering contractual netting arrangements. If a cross-default provision would have been triggered, settlement at fair value would have been required. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $22 million, $29 million and $15 million, respectively, and no cash collateral posted as of December 31, 2023. The other Registrant Subsidiaries had no derivative contracts with cross-default provisions outstanding as of December 31, 2023. The Registrant Subsidiaries' derivative contracts with cross-default provisions outstanding as of December 31, 2022 were not material.

11. FAIR VALUE MEASUREMENTS

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

Fair Value Measurements of Long-term Debt (Applies to all Registrants)

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value of AEP's Equity Units (Level 1) are valued based on publicly-traded securities issued by AEP.

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

	December 31,			
	2023		2022	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP (a)	$ 40,143.2	$ 37,325.7	$ 36,801.0	$ 35,915.9
AEP Texas	5,889.8	5,400.7	5,657.8	5,045.8
AEPTCo	5,414.4	4,796.9	4,782.8	3,940.5
APCo	5,588.3	5,390.1	5,410.5	5,079.2
I&M	3,499.4	3,291.6	3,260.8	2,929.0
OPCo	3,366.8	2,992.1	2,970.3	2,516.6
PSO	2,384.6	2,154.3	1,912.8	1,635.8
SWEPCo	3,646.9	3,209.7	3,391.6	2,870.9

(a) The fair value amounts include debt related to AEP's Equity Units and had a fair value of $0 million and $877 million as of December 31, 2023 and 2022, respectively. See "Equity Units" section of Note 14 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS. See "Other Temporary Investments" section of Note 1 for additional information.

The following is a summary of Other Temporary Investments and Restricted Cash:

	December 31, 2023			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash (a)	$ 48.9	$ —	$ —	$ 48.9
Other Cash Deposits	13.9	—	—	13.9
Fixed Income Securities – Mutual Funds (b)	165.9	—	(6.2)	159.7
Equity Securities – Mutual Funds	14.8	25.9	—	40.7
Total Other Temporary Investments and Restricted Cash	$ 243.5	$ 25.9	$ (6.2)	$ 263.2

	December 31, 2022			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash (a)	$ 47.1	$ —	$ —	$ 47.1
Other Cash Deposits	9.0	—	—	9.0
Fixed Income Securities – Mutual Funds (b)	152.4	—	(8.3)	144.1
Equity Securities – Mutual Funds	15.1	19.4	—	34.5
Total Other Temporary Investments and Restricted Cash	$ 223.6	$ 19.4	$ (8.3)	$ 234.7

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Years Ended December 31,		
	2023	**2022**	**2021**
		(in millions)	
Proceeds from Investment Sales	$ 7.6	$ 30.2	$ 15.0
Purchases of Investments	18.5	18.8	26.9
Gross Realized Gains on Investment Sales	1.1	6.1	3.6
Gross Realized Losses on Investment Sales	0.3	1.3	—

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1 for additional information.

The following is a summary of nuclear trust fund investments:

	December 31, 2023				2022			
	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments
	(in millions)							
Cash and Cash Equivalents	$ 16.8	$ —	$ —	$ —	$ 21.2	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,273.0	28.6	(3.9)	(33.2)	1,123.8	11.8	(14.9)	(18.8)
Corporate Debt	132.1	4.8	(5.2)	(8.6)	61.6	0.7	(7.7)	(9.6)
State and Local Government	1.7	—	—	—	3.3	0.1	—	(0.1)
Subtotal Fixed Income Securities	1,406.8	33.4	(9.1)	(41.8)	1,188.7	12.6	(22.6)	(28.5)
Equity Securities - Domestic	2,436.6	1,869.5	(0.9)	—	2,131.3	1,483.7	(6.4)	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,860.2	$ 1,902.9	$ (10.0)	$ (41.8)	$ 3,341.2	$ 1,496.3	$ (29.0)	$ (28.5)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31, 2023	2022	2021
		(in millions)	
Proceeds from Investment Sales	$ 2,787.5	$ 2,713.6	$ 1,886.4
Purchases of Investments	2,845.1	2,765.4	1,928.2
Gross Realized Gains on Investment Sales	99.0	52.4	103.2
Gross Realized Losses on Investment Sales	26.6	42.6	16.5

The base cost of fixed income securities was \$1.4 billion and \$1.2 billion as of December 31, 2023 and 2022, respectively. The base cost of equity securities was \$568 million and \$654 million as of December 31, 2023 and 2022, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2023 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 359.6
After 1 year through 5 years	597.6
After 5 years through 10 years	180.7
After 10 years	268.9
Total	$ 1,406.8

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

	December 31, 2023				
	Level 1	**Level 2**	**Level 3**	**Other**	**Total**
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 48.9	$ —	$ —	$ —	$ 48.9
Other Cash Deposits (a)	—	—	—	13.9	13.9
Fixed Income Securities – Mutual Funds	159.7	—	—	—	159.7
Equity Securities – Mutual Funds (b)	40.7	—	—	—	40.7
Total Other Temporary Investments and Restricted Cash	249.3	—	—	13.9	263.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	9.7	736.9	274.3	(617.0)	403.9
Cash Flow Hedges:					
Commodity Hedges (c)	—	123.5	19.8	(8.5)	134.8
Total Risk Management Assets	9.7	860.4	294.1	(625.5)	538.7
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.8	—	—	9.0	16.8
Fixed Income Securities:					
United States Government	—	1,273.0	—	—	1,273.0
Corporate Debt	—	132.1	—	—	132.1
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,406.8	—	—	1,406.8
Equity Securities – Domestic (b)	2,436.6	—	—	—	2,436.6
Total Spent Nuclear Fuel and Decommissioning Trusts	2,444.4	1,406.8	—	9.0	3,860.2
Total Assets	$ 2,703.4	$ 2,267.2	$ 294.1	$ (602.6)	$ 4,662.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 24.7	$ 783.8	$ 154.1	$ (600.3)	$ 362.3
Cash Flow Hedges:					
Commodity Hedges (c)	—	9.6	0.6	(8.5)	1.7
Interest Rate Hedges	—	9.0	—	—	9.0
Fair Value Hedges	—	98.4	—	—	98.4
Total Risk Management Liabilities	$ 24.7	$ 900.8	$ 154.7	$ (608.8)	$ 471.4

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 47.1	$ —	$ —	$ —	$ 47.1
Other Cash Deposits (a)	—	—	—	9.0	9.0
Fixed Income Securities – Mutual Funds	144.1	—	—	—	144.1
Equity Securities – Mutual Funds (b)	34.5	—	—	—	34.5
Total Other Temporary Investments and Restricted Cash	225.7	—	—	9.0	234.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	15.0	1,197.5	314.4	(1,211.5)	315.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	332.6	26.7	(52.8)	306.5
Interest Rate Hedges	—	11.0	—	—	11.0
Total Risk Management Assets	15.0	1,541.1	341.1	(1,264.3)	632.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	11.3	—	—	9.9	21.2
Fixed Income Securities:					
United States Government	—	1,123.8	—	—	1,123.8
Corporate Debt	—	61.6	—	—	61.6
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,188.7	—	—	1,188.7
Equity Securities – Domestic (b)	2,131.3	—	—	—	2,131.3
Total Spent Nuclear Fuel and Decommissioning Trusts	2,142.6	1,188.7	—	9.9	3,341.2
Total Assets	$ 2,383.3	$ 2,729.8	$ 341.1	$ (1,245.4)	$ 4,208.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 21.8	$ 870.9	$ 179.0	$ (731.9)	$ 339.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	74.3	1.7	(52.8)	23.2
Fair Value Hedges	—	127.4	—	—	127.4
Total Risk Management Liabilities	$ 21.8	$ 1,072.6	$ 180.7	$ (784.7)	$ 490.4

AEP Texas

	December 31, 2023									
	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Restricted Cash for Securitized Funding	$	34.0	$	—	$	—	$	—	$	34.0
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (c)	$	—	$	0.2	$	—	$	(0.2)	$	—
Cash Flow Hedges:										
Interest Rate Hedges		—		2.7		—		—		2.7
Total Risk Management Liabilities	$	—	$	2.9	$	—	$	(0.2)	$	2.7

	December 31, 2022									
	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Restricted Cash for Securitized Funding	$	32.7	$	—	$	—	$	—	$	32.7

APCo

	December 31, 2023									
	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Restricted Cash for Securitized Funding	$	14.9	$	—	$	—	$	—	$	14.9
Risk Management Assets										
Risk Management Commodity Contracts (c)		—		1.1		23.5		(2.2)		22.4
Total Assets	$	14.9	$	1.1	$	23.5	$	(2.2)	$	37.3
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (c)	$	—	$	24.0	$	1.1	$	(2.6)	$	22.5

	December 31, 2022									
	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Restricted Cash for Securitized Funding	$	14.4	$	—	$	—	$	—	$	14.4
Risk Management Assets										
Risk Management Commodity Contracts (c)		—		0.7		69.4		(1.0)		69.1
Total Assets	$	14.4	$	0.7	$	69.4	$	(1.0)	$	83.5
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (c)	$	—	$	4.6	$	0.3	$	(1.4)	$	3.5

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 37.4	$ 4.5	$ (2.3)	$ 39.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.8	—	—	9.0	16.8
Fixed Income Securities:					
United States Government	—	1,273.0	—	—	1,273.0
Corporate Debt	—	132.1	—	—	132.1
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,406.8	—	—	1,406.8
Equity Securities - Domestic (b)	2,436.6	—	—	—	2,436.6
Total Spent Nuclear Fuel and Decommissioning Trusts	2,444.4	1,406.8	—	9.0	3,860.2
Total Assets	$ 2,444.4	$ 1,444.2	$ 4.5	$ 6.7	$ 3,899.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 3.7	$ 1.7	$ (3.4)	$ 2.0

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 11.3	$ 5.3	$ (1.2)	$ 15.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	11.3	—	—	9.9	21.2
Fixed Income Securities:					
United States Government	—	1,123.8	—	—	1,123.8
Corporate Debt	—	61.6	—	—	61.6
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,188.7	—	—	1,188.7
Equity Securities - Domestic (b)	2,131.3	—	—	—	2,131.3
Total Spent Nuclear Fuel and Decommissioning Trusts	2,142.6	1,188.7	—	9.9	3,341.2
Total Assets	$ 2,142.6	$ 1,200.0	$ 5.3	$ 8.7	$ 3,356.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.6	$ 0.7	$ (1.3)	$ —

OPCo

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.2	$ 50.6	$ (0.1)	$ 50.7

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 40.0	$ (0.3)	$ 39.7

PSO

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 19.7	$ (0.7)	$ 19.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 29.6	$ 1.1	$ (0.8)	$ 29.9

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 24.0	$ 1.3	$ 25.3
Cash Flow Hedges:					
Interest Rate Hedges	—	1.6	—	(1.6)	—
Total Assets	$ —	$ 1.6	$ 24.0	$ (0.3)	$ 25.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 1.7	$ 0.3	$ (0.4)	$ 1.6

SWEPCo

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.5	$ 12.0	$ (0.9)	$ 11.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 15.7	$ 0.9	$ (1.0)	$ 15.6

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 2.2	$ 14.6	$ (0.4)	$ 16.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 1.6	$ 0.4	$ (0.6)	$ 1.4

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly-traded equity securities and equity-based mutual funds.

(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(d) The December 31, 2023 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(11) million in 2024 and $(4) million in 2025-2027; Level 2 matures $(99) million in 2024, $(44) million in periods 2025-2027, $7 million in periods 2028-2029 and $2 million in periods 2030-2033; Level 3 matures $74 million in 2024, $43 million in periods 2025-2027, $18 million in periods 2028-2029 and $(16) million in periods 2030-2033. 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, 2022 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(7) million in 2023; Level 2 matures $182 million in 2023, $134 million in periods 2024-2026; $10 million in periods 2027-2028 and $1 million in periods 2029-2033; Level 3 matures $128 million in 2023, $6 million in periods 2024-2026, $6 million in periods 2027-2028 and $(5) million in periods 2029-2033. Risk management commodity contracts are substantially comprised of power contracts.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2023	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2022	$ 160.4	$ 69.1	$ 4.6	$ (40.0)	$ 23.7	$ 14.2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	52.1	(11.7)	4.2	(3.6)	29.8	20.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	71.1	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(17.4)	—	—	—	—	—
Settlements	(172.2)	(57.3)	(8.8)	5.6	(53.4)	(34.2)
Transfers into Level 3 (d) (e)	(6.1)	—	—	—	—	—
Transfers out of Level 3 (e)	3.8	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	47.7	22.3	2.8	(12.6)	18.5	11.1
Balance as of December 31, 2023	$ 139.4	$ 22.4	$ 2.8	$ (50.6)	$ 18.6	$ 11.1

Year Ended December 31, 2022	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2021	$ 103.1	$ 41.7	$ (0.7)	$ (92.5)	$ 12.1	$ 10.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	69.5	3.0	3.7	6.5	24.2	35.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(34.9)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	9.6	—	—	—	—	—
Settlements	(154.6)	(44.7)	(3.0)	0.3	(36.3)	(45.0)
Transfers into Level 3 (d) (e)	1.7	—	—	—	—	—
Transfers out of Level 3 (e)	0.1	—	—	—	—	6.9
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	165.9	69.1	4.6	45.7	23.7	5.6
Balance as of December 31, 2022	$ 160.4	$ 69.1	$ 4.6	$ (40.0)	$ 23.7	$ 14.2

Year Ended December 31, 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)	48.6	8.3	(0.1)	2.4	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)	(45.2)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	24.2	—	—	—	—	—
Settlements	(89.0)	(28.0)	(2.2)	6.3	(26.4)	(15.5)
Transfers into Level 3 (d) (e)	(3.8)	—	—	—	—	—
Transfers out of Level 3 (e)	(34.4)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	89.4	42.1	(0.5)	9.1	12.1	15.3
Balance as of December 31, 2021	$ 103.1	$ 41.7	$ (0.7)	$ (92.5)	$ 12.1	$ 10.9

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Included in cash flow hedges on the statements of comprehensive income.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
December 31, 2023

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
		(in millions)						
AEP	Energy Contracts	$ 225.5	$ 144.9	Discounted Cash Flow	Forward Market Price (a)	$ 5.21	$ 153.77	$ 45.05
AEP	Natural Gas Contracts	—	0.5	Discounted Cash Flow	Forward Market Price (b)	3.11	3.11	3.11
AEP	FTRs	68.6	9.3	Discounted Cash Flow	Forward Market Price (a)	(25.45)	17.07	—
APCo	FTRs	23.5	1.1	Discounted Cash Flow	Forward Market Price (a)	(1.04)	6.45	1.36
I&M	FTRs	4.5	1.7	Discounted Cash Flow	Forward Market Price (a)	(1.48)	8.40	0.85
OPCo	Energy Contracts	—	50.6	Discounted Cash Flow	Forward Market Price (a)	22.92	67.53	42.85
PSO	FTRs	19.7	1.1	Discounted Cash Flow	Forward Market Price (a)	(25.45)	4.80	(4.33)
SWEPCo	Natural Gas Contracts	—	0.5	Discounted Cash Flow	Forward Market Price (b)	3.11	3.11	3.11
SWEPCo	FTRs	12.0	0.4	Discounted Cash Flow	Forward Market Price (a)	(25.45)	4.80	(4.33)

December 31, 2022

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
		(in millions)						
AEP	Energy Contracts	$ 204.0	$ 167.4	Discounted Cash Flow	Forward Market Price	$ 2.91	$ 187.34	$ 49.14
AEP	FTRs	137.1	13.3	Discounted Cash Flow	Forward Market Price	(36.45)	20.72	1.18
APCo	FTRs	69.4	0.3	Discounted Cash Flow	Forward Market Price	(2.82)	18.88	3.89
I&M	FTRs	5.3	0.7	Discounted Cash Flow	Forward Market Price	0.16	18.79	1.23
OPCo	Energy Contracts	—	40.0	Discounted Cash Flow	Forward Market Price	2.91	187.34	48.76
PSO	FTRs	24.0	0.3	Discounted Cash Flow	Forward Market Price	(36.45)	3.40	(7.55)
SWEPCo	FTRs	14.6	0.4	Discounted Cash Flow	Forward Market Price	(36.45)	3.40	(7.55)

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

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts, FTRs and Other Investments for the Registrants as of December 31, 2023 and 2022:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

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

Income Tax Expense (Benefit)

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

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (116.7)	$ 19.8	$ 93.9	$ 62.2	$ 93.2	$ 46.6	$ (60.8)	$ (88.1)
Deferred	115.9	63.5	52.3	(60.5)	(56.9)	2.8	2.9	59.9
Total Federal	(0.8)	83.3	146.2	1.7	36.3	49.4	(57.9)	(28.2)
State and Local:								
Current	69.0	2.7	9.1	6.3	21.1	(0.3)	0.3	1.0
Deferred	(13.6)	(0.1)	(8.2)	6.2	1.2	5.2	4.0	(6.1)
Total State and Local	55.4	2.6	0.9	12.5	22.3	4.9	4.3	(5.1)
Income Tax Expense (Benefit)	$ 54.6	$ 85.9	$ 147.1	$ 14.2	$ 58.6	$ 54.3	$ (53.6)	$ (33.3)

Year Ended December 31, 2022	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ 113.1	$ 29.0	$ 98.0	$ (61.0)	$ 43.4	$ (27.0)	$ (3.3)	$ (32.3)
Deferred	(88.8)	41.4	46.0	86.6	(51.3)	73.3	(50.5)	13.4
Total Federal	24.3	70.4	144.0	25.6	(7.9)	46.3	(53.8)	(18.9)
State and Local:								
Current	26.6	2.2	8.8	(0.4)	10.9	(0.3)	—	(1.8)
Deferred	(45.5)	—	16.3	(7.0)	1.2	(1.8)	4.6	(4.5)
Total State and Local	(18.9)	2.2	25.1	(7.4)	12.1	(2.1)	4.6	(6.3)
Income Tax Expense (Benefit)	$ 5.4	$ 72.6	$ 169.1	$ 18.2	$ 4.2	$ 44.2	$ (49.2)	$ (25.2)

Year Ended December 31, 2021	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (27.8)	$ (1.2)	$ 69.8	$ 5.0	$ 26.9	$ 6.8	$ (109.6)	$ (16.7)
Deferred	182.6	40.5	54.1	14.9	(35.5)	25.2	105.6	26.2
Total Federal	154.8	39.3	123.9	19.9	(8.6)	32.0	(4.0)	9.5
State and Local:								
Current	6.0	3.0	5.8	2.2	(0.6)	(3.1)	—	0.4
Deferred	(45.3)	0.8	14.4	—	(1.4)	5.5	8.1	(10.5)
Total State and Local	(39.3)	3.8	20.2	2.2	(2.0)	2.4	8.1	(10.1)
Income Tax Expense (Benefit)	$ 115.5	$ 43.1	$ 144.1	$ 22.1	$ (10.6)	$ 34.4	$ 4.1	$ (0.6)

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Income	$2,212.6	$ 370.4	$ 614.2	$ 294.4	$ 335.9	$ 328.2	$ 208.8	$ 223.8
Less: Equity Earnings	(1.4)	—	—	—	—	—	—	(1.4)
Income Tax Expense (Benefit)	54.6	85.9	147.1	14.2	58.6	54.3	(53.6)	(33.3)
Pretax Income	$2,265.8	$ 456.3	$ 761.3	$ 308.6	$ 394.5	$ 382.5	$ 155.2	$ 189.1
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 475.8	$ 95.8	$ 159.9	$ 64.8	$ 82.8	$ 80.3	$ 32.6	$ 39.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:								
Reversal of Origination Flow-Through	26.0	0.6	2.4	9.9	6.4	2.6	0.4	2.1
Investment Tax Credit Amortization	(50.3)	(0.7)	—	—	(1.6)	—	(1.4)	(0.2)
Production Tax Credits	(175.2)	—	—	(0.1)	—	—	(64.3)	(67.1)
State and Local Income Taxes, Net	43.7	2.1	0.7	9.9	17.5	3.9	3.5	(4.0)
Removal Costs	(22.0)	—	—	(5.1)	(11.8)	—	—	—
AFUDC	(39.8)	(6.0)	(17.5)	(5.5)	(2.3)	(3.6)	(1.8)	(2.4)
Tax Reform Excess ADIT Reversal	(151.1)	(6.0)	1.7	(17.3)	(30.0)	(28.9)	(23.3)	(12.6)
Remeasurement of Excess ADIT	(46.0)	—	—	(46.0)	—	—	—	—
Federal Return to Provision	—	(0.1)	—	3.4	(2.5)	(0.4)	0.6	1.0
Disallowance Cost	—	—	—	—	—	—	—	12.0
Other	(6.5)	0.2	(0.1)	0.2	0.1	0.4	0.1	(1.8)
Income Tax Expense (Benefit)	$ 54.6	$ 85.9	$ 147.1	$ 14.2	$ 58.6	$ 54.3	$ (53.6)	$ (33.3)
Effective Income Tax Rate	2.4 %	18.8 %	19.3 %	4.6 %	14.9 %	14.2 %	(34.5)%	(17.6)%

Year Ended December 31, 2022	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Income	$2,305.6	$ 307.9	$ 594.2	$ 394.2	$ 324.7	$ 287.8	$ 167.6	$ 294.3
Less: Equity Earnings	(1.4)	—	—	—	—	(0.6)	—	(1.4)
Income Tax Expense (Benefit)	5.4	72.6	169.1	18.2	4.2	44.2	(49.2)	(25.2)
Pretax Income	$2,309.6	$ 380.5	$ 763.3	$ 412.4	$ 328.9	$ 331.4	$ 118.4	$ 267.7
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 485.0	$ 79.9	$ 160.3	$ 86.6	$ 69.1	$ 69.6	$ 24.9	$ 56.2
Increase (Decrease) in Income Taxes Resulting from the Following Items:								
Reversal of Origination Flow-Through	17.1	—	—	4.7	2.9	3.0	—	2.3
Investment Tax Credit Amortization	(14.3)	—	—	—	(3.1)	—	(1.6)	—
Production Tax Credits	(197.1)	—	—	—	—	—	(47.7)	(57.1)
State and Local Income Taxes, Net	(14.0)	1.7	19.8	(5.9)	9.6	(1.6)	4.3	(4.9)
Removal Costs	(26.5)	—	—	(9.8)	(12.4)	—	—	—
AFUDC	(29.3)	(4.1)	(14.8)	(3.7)	(2.1)	(2.9)	—	—
Tax Reform Excess ADIT Reversal	(214.5)	(5.5)	—	(50.9)	(54.0)	(27.5)	(25.4)	(14.8)
Federal Return to Provision	(17.4)	—	—	(2.8)	(6.2)	3.5	(3.7)	—
Other	16.4	0.6	3.8	—	0.4	0.1	—	(6.9)
Income Tax Expense (Benefit)	$ 5.4	$ 72.6	$ 169.1	$ 18.2	$ 4.2	$ 44.2	$ (49.2)	$ (25.2)
Effective Income Tax Rate	0.2 %	19.1 %	22.2 %	4.4 %	1.3 %	13.3 %	(41.6)%	(9.4)%

Year Ended December 31, 2021	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Income	$2,488.1	$ 289.8	$ 591.7	$ 348.9	$ 279.8	$ 253.6	$ 141.1	$ 242.1
Less: Equity Earnings	(3.4)	—	—	—	—	—	—	(3.4)
Income Tax Expense (Benefit)	115.5	43.1	144.1	22.1	(10.6)	34.4	4.1	(0.6)
Pretax Income	$2,600.2	$ 332.9	$ 735.8	$ 371.0	$ 269.2	$ 288.0	$ 145.2	$ 238.1
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 546.0	$ 69.9	$ 154.5	$ 77.9	$ 56.5	$ 60.5	$ 30.5	$ 50.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:								
Reversal of Origination Flow-Through	25.9	—	—	11.7	3.5	2.2	—	1.8
Investment Tax Credit Amortization	(22.0)	—	—	—	(6.4)	—	(1.8)	—
Production Tax Credits	(98.8)	—	—	—	—	—	(6.0)	(7.2)
State and Local Income Taxes, Net	39.4	2.4	19.8	2.1	(1.3)	—	6.4	(8.0)
Removal Costs	(20.0)	—	—	(7.3)	(9.7)	—	—	—
AFUDC	(30.6)	(4.5)	(14.1)	(4.6)	(2.7)	(2.3)	—	—
Parent Company Loss Benefit	—	(3.2)	(18.3)	—	(2.8)	—	—	—
Tax Adjustments (a)	(55.1)	—	—	4.5	—	8.9	—	—
Tax Reform Excess ADIT Reversal	(255.6)	(21.3)	—	(60.5)	(46.3)	(32.6)	(25.4)	(31.1)
Federal Return to Provision	(1.6)	—	—	(1.6)	(0.6)	(1.2)	0.7	—
Other	(12.1)	(0.2)	2.2	(0.1)	(0.8)	(1.1)	(0.3)	(6.1)
Income Tax Expense (Benefit)	$ 115.5	$ 43.1	$ 144.1	$ 22.1	$ (10.6)	$ 34.4	$ 4.1	$ (0.6)
Effective Income Tax Rate	4.4 %	12.9 %	19.6 %	6.0 %	(3.9)%	11.9 %	2.8 %	(0.3)

(a) 2021 amount represents an out of period adjustment related to Deferred Income Taxes and Income Tax Expense (Benefit). Management concluded the misstatement and subsequent correction was not material to the 2021 or prior period financial statements.

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Deferred Tax Assets	$ 3,216.1	$ 173.6	$ 188.1	$ 473.0	$ 1,014.1	$ 271.4	$ 282.3	$ 441.5
Deferred Tax Liabilities	(12,631.8)	(1,401.4)	(1,335.8)	(2,484.9)	(2,184.0)	(1,424.1)	(1,113.5)	(1,620.8)
Net Deferred Tax Liabilities	$ (9,415.7)	$(1,227.8)	$ (1,147.7)	$(2,011.9)	$(1,169.9)	$ (1,152.7)	$ (831.2)	$ (1,179.3)
Property Related Temporary Differences	$ (7,779.7)	$(1,227.1)	$(1,134.6)	$(1,556.0)	$ (298.1)	$(1,162.1)	$ (817.2)	$ (1,087.2)
Amounts Due to Customers for Future Income Taxes	900.1	109.3	119.0	143.4	103.2	104.5	88.6	142.5
Deferred State Income Taxes	(1,222.8)	(41.5)	(155.4)	(308.4)	(238.1)	(68.8)	(122.6)	(238.6)
Securitized Assets	(79.9)	(45.6)	—	(29.2)	—	(5.1)	—	—
Regulatory Assets	(768.9)	(57.6)	(7.6)	(257.4)	32.3	(83.5)	(83.8)	(143.4)
Accrued Nuclear Decommissioning	(776.5)	—	—	—	(776.5)	—	—	—
Net Operating Loss Carryforward	148.0	—	3.9	—	—	2.6	25.3	47.5
Tax Credit Carryforward	321.9	13.7	—	0.1	7.2	41.0	53.8	68.6
Operating Lease Liability	131.1	16.6	0.3	15.1	10.8	14.6	23.6	26.3
Investment in Partnership	(293.1)	—	—	(0.1)	—	(0.7)	—	(1.3)
All Other, Net	4.1	4.4	26.7	(19.4)	(10.7)	4.8	1.1	6.3
Net Deferred Tax Liabilities	$ (9,415.7)	$(1,227.8)	$ (1,147.7)	$(2,011.9)	$(1,169.9)	$ (1,152.7)	$ (831.2)	$ (1,179.3)

Year Ended December 31, 2022	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Deferred Tax Assets	$ 3,567.4	$ 177.0	$ 165.0	$ 510.3	$ 933.7	$ 218.8	$ 225.0	$ 374.9
Deferred Tax Liabilities	(12,464.3)	(1,321.2)	(1,221.5)	(2,502.5)	(2,090.7)	(1,319.9)	(1,013.6)	(1,464.6)
Net Deferred Tax Liabilities	$ (8,896.9)	$ (1,144.2)	$ (1,056.5)	$(1,992.2)	$(1,157.0)	$ (1,101.1)	$ (788.6)	$ (1,089.7)
Property Related Temporary Differences	$ (7,788.1)	$ (1,130.7)	$ (1,081.5)	$(1,509.8)	$ (398.0)	$ (1,133.8)	$ (763.3)	$ (1,053.8)
Amounts Due to Customers for Future Income Taxes	962.7	111.0	118.5	163.0	114.3	112.6	96.0	146.2
Deferred State Income Taxes	(1,049.3)	(36.6)	(108.1)	(318.5)	(227.0)	(59.6)	(81.9)	(208.7)
Securitized Assets	(98.9)	(65.0)	—	(33.9)	—	—	—	—
Regulatory Assets	(865.2)	(48.9)	(1.1)	(301.2)	(29.5)	(57.6)	(140.2)	(114.1)
Accrued Nuclear Decommissioning	(632.7)	—	—	—	(632.7)	—	—	—
Net Operating Loss Carryforward	132.4	—	5.5	—	—	—	25.8	42.7
Tax Credit Carryforward	612.0	—	0.2	—	—	—	54.3	66.0
Operating Lease Liability	142.9	20.3	0.3	15.6	13.6	15.5	—	—
Investment in Partnership	(338.9)	—	—	—	—	—	—	—
Valuation Allowance	(28.2)	—	(0.1)	—	—	—	—	—
Deferred Revenues	7.1	—	—	—	—	—	—	—
Postretirement Benefits	2.5	—	—	—	—	—	—	—
All Other, Net	44.8	5.7	9.8	(7.4)	2.3	21.8	20.7	32.0
Net Deferred Tax Liabilities	$ (8,896.9)	$ (1,144.2)	$ (1,056.5)	$(1,992.2)	$(1,157.0)	$ (1,101.1)	$ (788.6)	$ (1,089.7)

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. AEP has agreed to extend the statute of limitations on the 2017-2019 tax returns to October 31, 2024, to allow time for our refund claim to be approved by the Congressional Joint Committee on Taxation. The statute of limitations for the 2020 return is set to naturally expire in October 2024 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. AEP has received and agreed to immaterial IRS proposed adjustments on the 2017 tax return. The IRS exam is complete, and AEP is currently waiting on the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

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. Generally, the statutes of limitations have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Net Income Tax Operating Loss Carryforward

As of December 31, 2023, AEP, OPCo, PSO and SWEPCo have state net income tax operating loss carryforwards as indicated in the table below:

Company	State/Municipality	State Net Income Tax Operating Loss Carryforward	Years of Expiration
		(in millions)	
AEP	Arkansas	$ 259.3	2024 - 2033
AEP	Colorado	80.8	2041
AEP	Illinois	54.4	2039 - 2041
AEP	Kentucky	204.1	2030 - 2037
AEP	Louisiana	629.2	NA
AEP	Michigan	45.6	2030 - 2032
AEP	Ohio Municipal	1,954.8	2024 - 2028
AEP	Oklahoma	877.9	2037
AEP	Pennsylvania	47.8	2030 - 2043
AEP	Tennessee	47.7	2032 - 2038
OPCo	Ohio Municipal	152.3	2024 - 2028
PSO	Oklahoma	947.1	2037
SWEPCo	Arkansas	258.9	2024 - 2033
SWEPCo	Louisiana	619.1	NA

NA Not applicable.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2019 and 2021 resulted in unused federal and state income tax credits. As of December 31, 2023, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041 and state tax credits will remain available indefinitely.

Company	Total Federal Tax Credit Carryforward	Total State Tax Credit Carryforward
	(in millions)	
AEP	$ 321.9	$ 40.0
AEP Texas	13.7	—
APCo	0.1	—
I&M	7.2	—
OPCo	41.0	—
PSO	53.8	40.0
SWEPCo	68.6	—

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

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that it is more-likely-than-not that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective evidence evaluated includes whether AEP has a history of recognizing income, future reversals of existing temporary differences and tax planning strategies.

Valuation allowance activity for the years ended December 31, 2023, 2022 and 2021 were not material.

Uncertain Tax Positions

The amount and activity of unrecognized tax benefits was not material for the Registrants for the years ended December 31, 2023, 2022 and 2021. Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for AEP as of December 31, 2023, 2022 and 2021 were $13 million, $23 million, and $14 million, respectively.

Federal Tax Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022, or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. As further significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, AEP will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

In December 2022, the IRS released Notice 2023-7, which provided initial CAMT guidance that AEP can begin to rely on in 2023. Notably, the interim guidance in Notice 2023-7 confirmed the CAMT depreciation adjustment includes tax depreciation that is capitalized to inventory under §263A and recovered as part of cost of goods sold, providing significant relief to AEP's potential CAMT exposure. In September 2023, the IRS released Notice 2023-64, which clarifies and supplements items in Notice 2023-7 and stated that additional guidance in the form of proposed regulations is expected. AEP will continue to monitor and assess any additional guidance.

AEP and subsidiaries expect to be applicable corporations for purposes of the CAMT beginning in 2023. CAMT cash taxes are expected to be partially offset by regulatory recovery, the utilization of tax credits and additionally the cash inflow generated by the sale of tax credits. The sale of tax credits are presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP presents the loss on sale of tax credits through income tax expense.

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits. In the third and fourth quarter of 2023, AEP, on behalf of PSO, SWEPCo and AEP Energy Supply, LLC, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $102 million received in the fourth quarter of 2023 and an additional $76 million expected in early 2024. AEP expects to continue to explore the ability to efficiently monetize its tax credits through third party transferability agreements.

13. LEASES

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

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

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

Operating lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. The amortization costs related to the Rockport finance lease were charged to Depreciation and Amortization. Interest on finance lease liabilities is generally charged to Interest Expense. Lease costs associated with capital projects are included in Property, Plant and Equipment on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Year Ended December 31, 2023	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Operating Lease Cost	$ 149.9	$ 34.0	$ 1.3	$ 18.5	$ 19.6	$ 17.3	$ 13.5	$ 17.5
Finance Lease Cost:								
Amortization of Right-of-Use Assets	69.1	7.4	—	8.3	7.3	5.0	3.3	19.9
Interest on Lease Liabilities	11.9	1.4	—	1.8	2.5	0.9	0.7	1.4
Total Lease Rental Costs (a)	$ 230.9	$ 42.8	$ 1.3	$ 28.6	$ 29.4	$ 23.2	$ 17.5	$ 38.8

Year Ended December 31, 2022	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Operating Lease Cost	$ 157.5	$ 18.4	$ 1.1	$ 17.9	$ 29.5	$ 16.9	$ 11.8	$ 15.3
Finance Lease Cost:								
Amortization of Right-of-Use Assets	205.5	6.8	—	7.9	78.7	4.9	3.2	10.8
Interest on Lease Liabilities	13.4	1.3	—	2.0	3.1	0.8	0.6	2.1
Total Lease Rental Costs (a)	$ 376.4	$ 26.5	$ 1.1	$ 27.8	$ 111.3	$ 22.6	$ 15.6	$ 28.2

Year Ended December 31, 2021	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Operating Lease Cost	$ 275.3	$ 18.4	$ 1.7	$ 19.3	$ 90.2	$ 19.0	$ 8.7	$ 12.1
Finance Lease Cost:								
Amortization of Right-of-Use Assets	74.7	6.7	—	7.7	12.9	4.9	3.2	11.0
Interest on Lease Liabilities	14.4	1.4	—	2.4	3.0	0.8	0.6	2.5
Total Lease Rental Costs (a)	$ 364.4	$ 26.5	$ 1.7	$ 29.4	$ 106.1	$ 24.7	$ 12.5	$ 25.6

(a) Excludes variable and short-term lease costs, which were immaterial.

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

December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	12.58	3.99	2.76	6.01	4.53	5.36	23.85	22.50
Finance Leases	4.63	5.13	0.00	4.16	4.95	4.97	5.76	4.78
Weighted-Average Discount Rate:								
Operating Leases	3.73 %	4.23 %	3.61 %	3.50 %	3.89 %	3.93 %	3.72 %	3.53 %
Finance Leases	6.19 %	5.27 %	— %	7.04 %	8.62 %	5.32 %	5.14 %	5.22 %

December 31, 2022	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	12.69	4.33	2.05	5.29	5.79	5.98	23.90	23.55
Finance Leases	4.61	5.39	0.00	4.25	4.76	5.27	6.02	4.13
Weighted-Average Discount Rate:								
Operating Leases	3.54 %	4.15 %	1.96 %	3.61 %	3.62 %	3.73 %	3.43 %	3.41 %
Finance Leases	5.76 %	4.75 %	— %	7.09 %	8.99 %	4.53 %	4.63 %	4.80 %

Year Ended December 31, 2023	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 146.8	$ 33.6	$ 1.3	$ 18.3	$ 19.5	$ 17.0	$ 12.5	$ 16.5
Operating Cash Flows Used for Finance Leases	11.9	1.4	—	1.8	2.5	0.9	0.7	1.4
Financing Cash Flows Used for Finance Leases	68.3	7.4	—	8.3	7.4	5.0	3.3	19.1
Non-cash Acquisitions Under Operating Leases	$ 99.8	$ 12.4	$ 1.2	$ 15.7	$ 7.9	$ 10.2	$ 15.5	$ 14.3

Year Ended December 31, 2022	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 155.1	$ 18.3	$ 1.0	$ 17.9	$ 29.7	$ 17.5	$ 10.5	$ 13.7
Operating Cash Flows Used for Finance Leases	13.6	1.3	—	2.0	3.2	0.8	0.6	2.1
Financing Cash Flows Used for Finance Leases	309.5	6.8	—	7.9	130.7	4.9	3.2	10.8
Non-cash Acquisitions Under Operating Leases	$ 191.4	$ 36.7	$ 1.7	$ 23.1	$ 19.1	$ 8.4	$ 46.0	$ 53.6

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

December 31, 2023	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 120.1	$ —	$ —	$ 41.0	$ 28.2	$ —	$ 0.6	$ 25.3
Other Property, Plant and Equipment	305.9	53.9	—	22.1	42.3	33.7	25.5	32.0
Total Property, Plant and Equipment	426.0	53.9	—	63.1	70.5	33.7	26.1	57.3
Accumulated Amortization	221.5	26.3	—	37.1	39.0	15.5	12.3	28.3
Net Property, Plant and Equipment Under Finance Leases	$ 204.5	$ 27.6	$ —	$ 26.0	$ 31.5	$ 18.2	$ 13.8	$ 29.0
Obligations Under Finance Leases:								
Noncurrent Liability	$ 139.9	$ 20.6	$ —	$ 17.8	$ 20.8	$ 13.2	$ 10.7	$ 18.8
Liability Due Within One Year	65.7	7.0	—	8.2	10.7	5.0	3.1	11.3
Total Obligations Under Finance Leases	$ 205.6	$ 27.6	$ —	$ 26.0	$ 31.5	$ 18.2	$ 13.8	$ 30.1

December 31, 2022	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 120.9	$ —	$ —	$ 41.1	$ 28.0	$ —	$ 0.6	$ 25.9
Other Property, Plant and Equipment	321.4	53.7	—	20.1	40.6	32.7	25.2	58.3
Total Property, Plant and Equipment	442.3	53.7	—	61.2	68.6	32.7	25.8	84.2
Accumulated Amortization	229.6	23.6	—	31.9	34.8	13.8	10.8	54.6
Net Property, Plant and Equipment Under Finance Leases	$ 212.7	$ 30.1	$ —	$ 29.3	$ 33.8	$ 18.9	$ 15.0	$ 29.6
Obligations Under Finance Leases:								
Noncurrent Liability	$ 168.4	$ 23.1	$ —	$ 21.6	$ 27.1	$ 14.2	$ 11.7	$ 31.3
Liability Due Within One Year	57.3	7.0	—	7.7	6.9	4.7	3.3	10.9
Total Obligations Under Finance Leases	$ 225.7	$ 30.1	$ —	$ 29.3	$ 34.0	$ 18.9	$ 15.0	$ 42.2

December 31, 2023	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Operating Lease Assets	$ 620.2	$ 77.6	$ 2.6	$ 73.7	$ 53.8	$ 69.9	$ 112.8	$ 126.3
Obligations Under Operating Leases:								
Noncurrent Liability	$ 519.4	$ 50.9	$ 1.4	$ 59.8	$ 37.7	$ 56.7	$ 106.8	$ 122.5
Liability Due Within One Year	115.7	28.7	1.3	14.6	16.8	13.5	10.1	9.0
Total Obligations Under Operating Leases	$ 635.1	$ 79.6	$ 2.7	$ 74.4	$ 54.5	$ 70.2	$ 116.9	$ 131.5

December 31, 2022	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 645.5	$ 94.7	$ 2.7	$ 73.6	$ 64.3	$ 73.8	$ 106.1	$ 123.4
Obligations Under Operating Leases:								
Noncurrent Liability	$ 552.5	$ 67.8	$ 1.5	$ 59.1	$ 48.9	$ 60.3	$ 99.3	$ 120.2
Liability Due Within One Year	113.6	28.6	1.3	15.0	16.0	13.5	8.9	8.4
Total Obligations Under Operating Leases	$ 666.1	$ 96.4	$ 2.8	$ 74.1	$ 64.9	$ 73.8	$ 108.2	$ 128.6

Future minimum lease payments consisted of the following as of December 31, 2023:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2024	$ 76.8	$ 8.3	$ —	$ 9.9	$ 12.8	$ 5.8	$ 3.7	$ 12.6
2025	48.6	6.6	—	8.5	7.2	4.3	2.9	4.6
2026	33.0	5.1	—	3.5	4.5	3.1	2.5	3.9
2027	26.2	4.0	—	2.3	4.0	2.5	2.0	3.5
2028	19.2	2.8	—	1.9	3.3	2.0	1.7	3.0
After 2028	35.4	5.1	—	3.4	7.3	3.2	3.3	7.2
Total Future Minimum Lease Payments	239.2	31.9	—	29.5	39.1	20.9	16.1	34.8
Less: Imputed Interest	33.6	4.3	—	3.5	7.6	2.7	2.3	4.7
Estimated Present Value of Future Minimum Lease Payments	$ 205.6	$ 27.6	$ —	$ 26.0	$ 31.5	$ 18.2	$ 13.8	$ 30.1

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2024	$ 141.6	$ 32.1	$ 1.4	$ 17.8	$ 18.9	$ 16.9	$ 12.2	$ 16.2
2025	103.3	15.7	0.7	14.8	10.6	15.3	11.1	15.0
2026	92.0	13.3	0.4	13.3	9.7	14.1	10.3	12.9
2027	82.6	10.7	0.2	12.1	8.9	12.8	9.3	11.5
2028	67.4	7.8	0.1	10.0	7.0	10.6	7.9	9.5
After 2028	327.6	8.1	—	16.8	4.8	9.1	129.1	135.6
Total Future Minimum Lease Payments	814.5	87.7	2.8	84.8	59.9	78.8	179.9	200.7
Less: Imputed Interest	179.4	8.1	0.1	10.4	5.4	8.6	63.0	69.2
Estimated Present Value of Future Minimum Lease Payments	$ 635.1	$ 79.6	$ 2.7	$ 74.4	$ 54.5	$ 70.2	$ 116.9	$ 131.5

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2023, 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	$ 45.3
AEP Texas	10.9
APCo	5.8
I&M	4.1
OPCo	7.2
PSO	4.7
SWEPCo	5.4

Lessor Activity

The Registrants’ lessor activity was immaterial as of and for the twelve months ended December 31, 2023 and December 31, 2022, respectively.

14. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

The following table is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury	
Balance, December 31, 2020	516,808,354	20,204,160	
Issued	7,607,821	—	
Balance, December 31, 2021	524,416,175	20,204,160	
Issued	683,146	—	
Treasury Stock Reissued	—	(8,970,920)	(a)
Balance, December 31, 2022	525,099,321	11,233,240	
Issued	2,269,836	—	
Treasury Stock Reissued	—	(10,048,668)	(a)
Balance, December 31, 2023	527,369,157	1,184,572	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Equity Units. See "Equity Units" section below for additional information.

ATM Program

In 2023, 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 $1.7 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. There were no issuances under the ATM program for the year ended December 31, 2023.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2023	Interest Rate Ranges as of December 31, 2023	2022	Outstanding as of December 31, 2023	2022
AEP					(in millions)	
Senior Unsecured Notes	2024-2053	4.23%	1.00%-8.13%	0.75%-8.13%	$ 33,779.4	$ 30,174.8
Pollution Control Bonds (a)	2024-2036 (b)	2.98%	0.63%-4.90%	0.63%-4.55%	1,771.6	1,770.2
Notes Payable – Nonaffiliated (c)	2024-2028	4.67%	0.93%-6.59%	0.93%-6.37%	193.3	269.7
Securitization Bonds	2024-2029 (d)	2.97%	2.06%-3.77%	2.01%-3.77%	368.9	487.8
Spent Nuclear Fuel Obligation (e)					300.4	285.6
Junior Subordinated Notes (f)	2024-2027	3.90%	2.03%-5.70%	1.30%-3.88%	2,388.1	2,381.3
Other Long-term Debt	2024-2059	6.58%	3.00%-13.72%	1.15%-13.72%	1,341.5	1,431.6
Total Long-term Debt Outstanding					$ 40,143.2	$ 36,801.0
AEP Texas						
Senior Unsecured Notes	2025-2052	4.20%	2.10%-6.76%	2.10%-6.76%	$ 5,027.2	$ 4,702.7
Pollution Control Bonds	2029-2030 (b)	3.88%	2.60%-4.55%	0.90%-4.55%	440.3	440.2
Securitization Bonds	2024-2029 (d)	2.43%	2.06%-2.84%	2.06%-2.84%	221.8	314.4
Other Long-term Debt	2025-2059	6.70%	4.50%-6.71%	4.50%-5.67%	200.5	200.5
Total Long-term Debt Outstanding					$ 5,889.8	$ 5,657.8
AEPTCo						
Senior Unsecured Notes	2024-2053	4.02%	2.75%-5.52%	2.75%-5.52%	$ 5,414.4	$ 4,782.8
Total Long-term Debt Outstanding					$ 5,414.4	$ 4,782.8
APCo						
Senior Unsecured Notes	2025-2050	4.68%	2.70%-7.00%	2.70%-7.00%	$ 4,584.9	$ 4,581.4
Pollution Control Bonds (a)	2024-2036 (b)	2.89%	0.63%-4.90%	0.63%-3.80%	430.0	429.4
Securitization Bonds	2028 (d)	3.77%	3.77%	2.01%-3.77%	147.0	173.3
Other Long-term Debt	2024-2026	6.53%	6.46%-13.72%	4.84%-13.72%	426.4	226.4
Total Long-term Debt Outstanding					$ 5,588.3	$ 5,410.5
I&M						
Senior Unsecured Notes	2028-2053	4.52%	3.25%-6.05%	3.20%-6.05%	$ 2,843.6	$ 2,597.3
Pollution Control Bonds (a)	2025 (b)	2.49%	0.75%-3.05%	0.75%-3.05%	189.4	189.0
Notes Payable – Nonaffiliated (c)	2024-2028	5.08%	0.93%-6.59%	0.93%-5.93%	163.3	183.8
Spent Nuclear Fuel Obligation (e)					300.4	285.6
Other Long-term Debt	2025	6.00%	6.00%	6.00%	2.7	5.1
Total Long-term Debt Outstanding					$ 3,499.4	$ 3,260.8
OPCo						
Senior Unsecured Notes	2030-2051	4.00%	1.63%-6.60%	1.63%-6.60%	$ 3,366.8	$ 2,969.7
Other Long-term Debt		—%	—%	1.15%	—	0.6
Total Long-term Debt Outstanding					$ 3,366.8	$ 2,970.3
PSO						
Senior Unsecured Notes	2025-2051	4.05%	2.20%-6.63%	2.20%-6.63%	$ 2,257.8	$ 1,785.6
Other Long-term Debt	2025-2027	6.65%	3.00%-6.71%	3.00%-5.75%	126.8	127.2
Total Long-term Debt Outstanding					$ 2,384.6	$ 1,912.8
SWEPCo						
Senior Unsecured Notes	2026-2051	3.73%	1.65%-6.20%	1.65%-6.20%	$ 3,646.9	$ 3,297.6
Notes Payable – Nonaffiliated (c)		—%	—%	4.58%-6.37%	—	55.9
Other Long-term Debt		—%	—%	4.68%	—	38.1
Total Long-term Debt Outstanding					$ 3,646.9	$ 3,391.6

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.
(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.
(e) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See “Spent Nuclear Fuel Disposal” section of Note 6 for additional information.
(f) See “Equity Units” section below for additional information.

As of December 31, 2023, outstanding long-term debt was payable as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2024	$ 2,490.5	$ 96.0	$ 95.0	$ 538.8	$ 83.7	$ —	$ 0.6	$ —
2025	3,308.5	524.5	90.0	673.3	241.2	—	250.6	—
2026	1,780.5	75.0	425.0	30.9	26.3	—	50.6	900.0
2027	2,215.9	25.6	—	355.6	4.1	—	0.3	—
2028	2,326.6	526.2	60.0	31.8	350.8	—	—	575.0
After 2028	28,349.7	4,690.2	4,806.0	4,000.0	2,825.4	3,400.0	2,100.0	2,200.0
Principal Amount	40,471.7	5,937.5	5,476.0	5,630.4	3,531.5	3,400.0	2,402.1	3,675.0
Unamortized Discount, Net and Debt Issuance Costs	(328.5)	(47.7)	(61.6)	(42.1)	(32.1)	(33.2)	(17.5)	(28.1)
Total Long-term Debt Outstanding	$ 40,143.2	$ 5,889.8	$ 5,414.4	$ 5,588.3	$ 3,499.4	$ 3,366.8	$ 2,384.6	$ 3,646.9

Long-term Debt Subsequent Events

In January and February 2024, I&M retired $8 million and $8 million, respectively, of Notes Payable related to DCC Fuel.

In January and February 2024, Transource Energy issued $16 million and $2 million, respectively, of variable rate Other Long-term Debt due in 2025.

In February 2024, AEP Texas retired $12 million of Securitization Bonds.

In February 2024, APCo retired $13 million of Securitization Bonds.

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 due in 2025 and a forward equity purchase contract which settled after three years in August 2023. In June 2023, AEP successfully remarketed the Junior Subordinated Notes on behalf of holders of the corporate units. AEP did not receive any proceeds from the remarketing which were used to purchase a portfolio of treasury securities that matured on August 14, 2023. On August 15, 2023, the proceeds from the treasury portfolio were used to settle the forward equity purchase contract with AEP. The interest rate on the Junior Subordinated Notes was reset to 5.699% with the maturity remaining in 2025. In August 2023, AEP issued 10,048,668 shares of AEP common stock and received proceeds totaling $850 million under the settlement of the forward equity purchase contract. AEP common stock held in treasury was used to settle the forward equity purchase contract. The proceeds were used to pay down debt balances and support AEP's overall capital expenditure plans.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 1.3% of consolidated tangible net assets as of December 31, 2023. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreement.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. 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 APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2023, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $16.6 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2023, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 3,003.4 (a)	$ 737.1	$ —	$ 721.5	$ 702.6	$ —	$ 1.3	$ 337.3

(a) Includes the restrictions of consolidated and non-consolidated subsidiaries.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements. As of December 31, 2023, AEP had $7.6 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.8 billion, $1.6 billion and $1.5 billion of dividends to common shareholders for the years ended December 31, 2023, 2022 and 2021, respectively.

Lines of Credit and Short-term Debt (Applies to AEP)

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. As of December 31, 2023, AEP had $5 billion in revolving credit facilities to support its commercial paper program. Securitized Debt for Receivables, for the year ended 2023, had a weighted-average interest rate of 5.33% and a maximum amount outstanding of $900 million. The commercial paper program, for the year ended 2023, had a weighted-average interest rate of 5.38% and a maximum amount outstanding of $3.2 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2023		2022	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(in millions)		(in millions)	
AEP	Securitized Debt for Receivables (b)	$ 888.0	5.65 %	$ 750.0	4.67 %
AEP	Commercial Paper	1,937.9	5.69 %	2,862.2	4.80 %
AEP	Term Loan	—	— %	125.0	5.17 %
AEP	Term Loan	—	— %	150.0	5.17 %
AEP	Term Loan	—	— %	100.0	5.23 %
AEP	Term Loan	—	— %	125.0	4.87 %
SWEPCo	Notes Payable	4.3	7.71 %	—	— %
	Total Short-term Debt	$ 2,830.2		$ 4,112.2	

(a) Weighted-average rate as of December 31, 2023 and 2022, respectively.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program (Applies to Registrant Subsidiaries)

AEP subsidiaries use 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 Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2023 and 2022 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2023:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2023	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 477.5	$ 42.0	$ 216.8	$ 12.9	$ (103.7)	$ 600.0	
AEPTCo	471.3	309.4	135.6	70.5	(62.8)	820.0	(a)
APCo	388.6	19.8	283.5	19.0	(320.7)	750.0	
I&M	475.3	112.2	84.0	44.2	(63.3)	500.0	
OPCo	485.7	64.7	183.0	40.2	(110.5)	500.0	
PSO	375.0	121.5	92.5	49.6	(54.4)	750.0	
SWEPCo	401.6	25.8	150.7	16.5	(88.7)	750.0	

Year Ended December 31, 2022:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2022	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 348.8	$ 652.3	$ 173.3	$ 247.8	$ (96.5)	$ 500.0	
AEPTCo	480.2	137.0	189.4	28.9	(195.5)	820.0	(a)
APCo	438.4	214.2	181.7	45.4	(162.4)	500.0	
I&M	318.6	23.0	105.2	22.3	(226.9)	500.0	
OPCo	262.5	246.1	101.3	86.9	(172.9)	500.0	
PSO	364.2	432.5	224.5	402.8	(364.2)	400.0	
SWEPCo	358.4	156.6	219.3	109.7	(310.7)	400.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above tables does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2023 and 2022 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2023:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2023
		(in millions)	
AEP Texas	$ 7.1	$ 6.9	$ 7.1
SWEPCo	2.8	2.4	2.2

Year Ended December 31, 2022:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2022
		(in millions)	
AEP Texas	$ 7.0	$ 6.8	$ 6.9
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 December 31, 2023 and 2022 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2023:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2023	Loans to AEP as of December 31, 2023	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 44.4	$ 158.1	$ 3.9	$ 64.2	$ 44.4	$ —	$ 50.0	(a)

Year Ended December 31, 2022:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2022	Loans to AEP as of December 31, 2022	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 52.4	$ 141.8	$ 6.7	$ 57.5	$ 29.4	$ —	$ 50.0	(a)

(a) Amount represents the authorized short-term borrowing limit from FERC or state regulatory agencies not otherwise included in the utility money pool above.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Years Ended December 31,		
	2023	2022	2021
Maximum Interest Rate	5.81 %	5.28 %	0.48 %
Minimum Interest Rate	4.66 %	0.10 %	0.02 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for the Years Ended December 31,		
Company	2023	2022	2021	2023	2022	2021
AEP Texas	5.46 %	1.08 %	0.33 %	5.71 %	1.99 %	0.26 %
AEPTCo	5.41 %	1.81 %	0.32 %	5.56 %	2.47 %	0.10 %
APCo	5.54 %	2.34 %	0.41 %	5.54 %	2.39 %	0.25 %
I&M	5.14 %	2.57 %	0.33 %	5.57 %	2.20 %	0.23 %
OPCo	5.43 %	3.51 %	0.27 %	5.60 %	1.22 %	0.14 %
PSO	5.51 %	2.65 %	0.34 %	5.35 %	0.75 %	0.07 %
SWEPCo	5.34 %	2.80 %	0.26 %	5.72 %	0.55 %	0.18 %

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

Year Ended December 31,	Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
2023	AEP Texas	5.81 %	4.66 %	5.54 %
2023	SWEPCo	5.81 %	4.66 %	5.56 %
2022	AEP Texas	5.28 %	0.46 %	2.23 %
2022	SWEPCo	5.28 %	0.46 %	2.23 %
2021	AEP Texas	0.58 %	0.21 %	0.37 %
2021	SWEPCo	0.58 %	0.21 %	0.37 %

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

Year Ended December 31,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2023	5.81 %	4.53 %	5.81 %	4.53 %	5.56 %	5.51 %
2022	5.28 %	0.46 %	5.28 %	0.46 %	2.08 %	2.07 %
2021	0.86 %	0.25 %	0.86 %	0.25 %	0.38 %	0.35 %

Interest expense related to short-term borrowing activities with the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries incurred interest expense for all short-term borrowing activities as follows:

	Years Ended December 31,		
Company	2023	2022	2021
		(in millions)	
AEP Texas	$ 10.8	$ 0.9	$ 0.3
AEPTCo	7.6	3.5	0.6
APCo	16.8	5.6	0.1
I&M	3.2	2.9	0.2
OPCo	9.7	2.3	0.1
PSO	2.3	5.5	0.3
SWEPCo	7.9	4.9	0.3

Interest income related to short-term lending activities with the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Income, unless shown as Other Income due to materiality, on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries earned interest income for all short-term lending activities as follows:

	Years Ended December 31,		
Company	2023	2022	2021
		(in millions)	
AEP Texas	$ 0.1	$ 2.6	$ 0.1
AEPTCo	7.0	1.6	0.4
APCo	1.1	2.8	0.3
I&M	2.4	0.5	0.2
OPCo	0.1	0.4	0.1
PSO	1.5	0.3	—
SWEPCo	0.2	0.2	0.1

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables. The agreement was amended in August 2023 to increase the commitment from $750 million and expires in September 2025. As of December 31, 2023, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31,		
	2023	2022	2021
		(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	5.33 %	1.84 %	0.19 %
Net Uncollectible Accounts Receivable Written Off	$ 30.7	$ 29.5	$ 26.5

	December 31, 2023	December 31, 2022
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,207.4	$ 1,167.7
Short-term – Securitized Debt of Receivables	888.0	750.0
Delinquent Securitized Accounts Receivable	52.2	44.2
Bad Debt Reserves Related to Securitization	42.0	39.7
Unbilled Receivables Related to Securitization	409.8	360.9

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEP Texas and AEPTCo)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. KPCo ceased selling accounts receivable to AEP Credit in the first quarter of 2022, based on the expected sale to Liberty. As a result, in the first quarter of 2022, KPCo recorded an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. In the third quarter of 2023, KPCo resumed selling accounts receivable to AEP Credit, due to the termination of the sale to Liberty, and the balance in KPCo's allowance for uncollectible accounts was reversed. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were:

Company	December 31, 2023	December 31, 2022
	(in millions)	
APCo	$ 184.6	$ 194.4
I&M	156.4	166.9
OPCo	541.7	478.6
PSO	134.6	155.5
SWEPCo	168.3	194.0

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

Company	Years Ended December 31, 2023	2022	2021 (a)
		(in millions)	
APCo	$ 16.9	$ 9.4	$ 4.9
I&M	16.3	9.7	7.0
OPCo	29.5	29.8	8.3
PSO	15.3	7.4	3.4
SWEPCo	18.5	9.4	5.4

(a) In 2021, due to the successful collection of accounts receivable balances during the COVID-19 pandemic, the allowance for doubtful accounts was reduced, 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:

Company	Years Ended December 31, 2023	2022	2021
		(in millions)	
APCo	$ 1,819.8	$ 1,552.9	$ 1,324.1
I&M	2,054.8	2,045.6	1,927.0
OPCo	3,339.3	3,101.3	2,458.5
PSO	1,944.5	1,809.5	1,406.4
SWEPCo	1,866.4	1,858.4	1,636.1

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

Awards under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP), which replaced prior long-term incentive plans effective April 2015, may be granted to employees and directors. The 2015 LTIP was subsequently amended in September 2016. The 2015 LTIP provides for a maximum of 10 million AEP common shares to be available for grant to eligible employees and directors. As of December 31, 2023, 3,698,144 shares remained available for issuance under the 2015 LTIP. No new awards may be granted under the Prior Plan. Awards granted under the 2015 LTIP awards may be made in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards. Shares issued pursuant to a stock option or a stock appreciation right reduce the shares remaining available for grants under the 2015 LTIP by 0.286 of a share. Each share issued for any other award that settles in AEP stock reduces the shares remaining available for grants under the 2015 LTIP by one share. Cash settled awards do not reduce the number of shares remaining available under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Shares

Performance units granted prior to 2017 were settled in cash rather than AEP common stock and did not reduce the number of shares remaining available under the 2015 LTIP. Those performance units had a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. Performance shares granted in and after 2017 are settled in AEP common stock and reduce the aggregate share authorization. In all cases the number of performance shares held at the end of the three-year performance period is multiplied by the performance score for such period to determine the actual number of performance shares that participants realize. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy a minimum stock ownership requirement. If those employees have not met their stock ownership requirement, a portion or all of their performance shares are mandatorily deferred upon vesting into AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to a share of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance shares and AEP career shares accrue as additional shares. Management records compensation cost for performance shares over an approximately three-year vesting period. Performance shares are recorded as mezzanine equity on the balance sheets until the vesting date and compensation cost is calculated at fair value based on the performance metrics for each grant. Performance shares granted in 2023, 2022 and 2021 have three performance metrics: (a) three-year cumulative operating earnings per-share with a 50% weight, (b) relative total shareholder return with a 40% weight and (c) renewable generation additions (2023 grants) or non-emitting generation capacity as a percentage of total owned and purchased capacity (2022 and 2021 grants) with a 10% weight. The three-year cumulative operating earnings per-share and renewable generation additions or non-emitting generating capacity metrics are adjusted quarterly for changes in performance relative to the metric approved by the HR Committee. The total shareholder return metric is measured relative to a peer group of similar companies and is based on a third-party Monte Carlo valuation. The value related to this metric does not change over the three-year vesting period.

The HR Committee awarded performance shares and reinvested dividends on outstanding performance shares and AEP career shares as follows:

Performance Shares	Years Ended December 31, 2023	2022	2021
Awarded Shares (in thousands)	486.7	530.3	565.0
Weighted-Average Share Fair Value at Grant Date	$ 98.63	$ 97.61	$ 81.02
Vesting Period (in years)	3	3	3

Performance Shares and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2023	2022	2021
Awarded Shares (in thousands)	81.3	63.3	74.5
Weighted-Average Fair Value at Grant Date	$ 82.02	$ 98.73	$ 84.48
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance shares is equal to the remaining life of the related performance shares. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.

Performance scores and final awards are determined and approved by the HR Committee in accordance with the pre-established performance measures within approximately two months after the end of the performance period.

The certified performance scores and shares earned for the three-year periods were as follows:

Performance Shares	Years Ended December 31, 2023	2022	2021
Certified Performance Score	106.1 %	131.1 %	102.9 %
Performance Shares Earned	540,863	512,660	537,166
Performance Shares Mandatorily Deferred as AEP Career Shares	70,377	28,282	14,613
Performance Shares Voluntarily Deferred into the Incentive Compensation Deferral Program	22,716	23,609	22,915
Performance Shares to be Settled (a)	447,770	460,769	499,638

(a) Performance shares settled in AEP common stock in the quarter following the end of the year shown.

The settlements were as follows:

Performance Shares and AEP Career Shares	Years Ended December 31, 2023	2022	2021
		(in millions)	
AEP Common Stock Settlements for Performance Shares	$ 41.8	$ 43.2	$ 54.7
AEP Common Stock Settlements for Career Share Distributions	8.3	5.1	4.0

A summary of the status of AEP's nonvested Performance Shares as of December 31, 2023 and changes during the year ended December 31, 2023 were as follows:

Nonvested Performance Shares	Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2023	1,012.2	$ 90.27
Awarded	486.7	98.63
Dividends	59.8	82.02
Vested (a)	(514.6)	82.33
Forfeited	(154.2)	86.73
Nonvested as of December 31, 2023	889.9	99.49

(a) The vested Performance Shares will be converted to 448 thousand shares based on the closing share price on the day before settlement.

Monte Carlo Valuation

AEP engages a third-party for a Monte Carlo valuation to calculate the fair value of the total shareholder return metric for the performance shares awarded during and after 2017. The valuations use a lattice model and the expected volatility assumptions used were the historical volatilities for AEP and the members of their peer group. The assumptions used in the Monte Carlo valuations were as follows:

Assumptions	Years Ended December 31, 2023	2022	2021
Valuation Period (in years) (a)	2.87	2.86	2.88
Expected Volatility Minimum	21.23 %	25.92 %	25.87 %
Expected Volatility Maximum	39.00 %	40.82 %	39.90 %
Expected Volatility Average	25.35 %	31.09 %	31.01 %
Dividend Rate (b)	— %	— %	— %
Risk Free Rate	4.32 %	1.64 %	0.19 %

(a) Period from award date to vesting date.
(b) Equivalent to reinvesting dividends.

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued AEP employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date, subject to the participant's continued AEP employment, as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. The RSU compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

The HR Committee awarded RSUs, including additional units awarded as dividends, as follows:

Restricted Stock Units	Years Ended December 31, 2023	2022	2021
Awarded Units (in thousands)	268.4	290.4	280.0
Weighted-Average Grant Date Fair Value	$ 88.52	$ 90.48	$ 80.39

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

Restricted Stock Units	Years Ended December 31, 2023	2022	2021
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 18.8	$ 17.8	$ 20.5
Intrinsic Value of Restricted Stock Units Vested (a)	19.0	20.3	22.0

(a) Intrinsic value is calculated as market price at the vesting date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2023 and changes during the year ended December 31, 2023 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2023	459.6	$ 88.05
Awarded	268.4	88.52
Vested	(212.4)	88.47
Forfeited	(84.5)	86.84
Nonvested as of December 31, 2023	431.1	88.57

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2023 was $33 million and the weighted-average remaining contractual life was 1.5 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan (SUAP) for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of the compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested on their grant date. Stock units are paid to directors upon termination of their board service or up to 10 years later if the participant so elects. Cash settlements for stock units were calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. Effective June 30, 2022, the SUAP was amended to pay stock units in AEP common stock rather than cash.

Management records compensation costs for stock units when the units are awarded and prior to June 2022 adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

After five years of service on the Board of Directors, non-employee directors receive subsequent AEP stock units as contributions to an AEP stock fund under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan. These balances are paid in cash upon termination of board service or up to 10 years later if the participant so elects.

AEP common stock and cash settlements for stock unit distributions were immaterial for the years ended December 31, 2023, 2022 and 2021.

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

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2023**	**2022**	**2021**
Awarded Units (in thousands)	19.8	14.5	12.6
Weighted-Average Grant Date Fair Value	$ 82.14	$ 95.16	$ 84.54

Share-based Compensation Plans

For share-based payment arrangements the compensation cost, the actual tax benefit from the tax deductions for compensation cost recognized in income and the total compensation cost capitalized were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2023**	**2022**	**2021**
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 50.9	$ 63.3	$ 61.1
Actual Tax Benefit	6.4	8.0	8.7
Total Compensation Cost Capitalized	15.3	16.0	16.9

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

As of December 31, 2023, there was $66 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance shares is adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.4 years.

Under the 2015 LTIP, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. AEP's current practice is to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset tax withholding obligations.

16. RELATED PARTY TRANSACTIONS

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

For other related party transactions, also see "Income Taxes and Investment and Production Tax Credits" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective Off-system Sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

Joint License Agreement (Applies to all Registrant Subsidiaries except AEP Texas and SWEPCo)

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the costs related to these agreements in Other Operation expense on the statements of income. APCo, I&M, KPCo, OPCo, PSO and WPCo recorded income related to these agreements in Sales to AEP Affiliates on the statements of income. The impact of the joint license agreement for the years ended December 31, 2023, 2022 and 2021 was not material.

Unit Power Agreements (Applies to I&M)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The UPA will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028). I&M's direct purchases from AEGCo were $181 million, $242 million and $218 million for the years ended December 31, 2023, 2022 and 2021, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on I&M's statements of income.

Ohio Auctions (Applies to OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy and AEPEP participate in the auction process and have been awarded tranches of OPCo's SSO load. OPCo's auction purchases were $87 million, $10 million and $52 million for the years ended December 31, 2023, 2022 and 2021, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on OPCo's statements of income.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2023, 2022 and 2021 were not material. These sales and purchases are recorded in Property, Plant and Equipment on the balance sheets.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. Charitable contributions to the AEP Foundation were not made in 2023 or 2021. Charitable contributions were recorded in Other Operation expenses on the statements of income as follows for the year ended December 31, 2022:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Contributions to AEP Foundation	$ 75.0	$ 9.9	$ 11.1	$ 12.5	$ 11.0	$ 8.1	$ 5.8	$ 8.8

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

	Years Ended December 31,		
Company	**2023**	**2022**	**2021**
		(in millions)	
AEGCo	$ 9.3	$ 11.3	$ 7.6
APCo	39.2	36.1	40.1
KPCo	—	2.0	3.1
WPCo	10.6	4.7	3.2

AEP Wind Holdings LLC PPAs (Applies to I&M, OPCo and SWEPCo)

Prior to acquisition, Fowler Ridge 2 had PPAs with I&M and OPCo and Flat Ridge 2 had a PPA with SWEPCo for a portion of their energy production. The following table shows the amounts of purchased electricity by I&M, PSO and SWEPCo:

	Years Ended December 31,		
Company	**2023**	**2022**	**2021**
		(in millions)	
I&M	$ 8.0	$ 11.8	$ 9.9
OPCo	16.1	23.6	19.6
SWEPCo	—	13.7	14.5

See Note 7 - Acquisitions, Dispositions and Impairments for additional information related to the disposal of the 50% interests in Fowler Ridge 2 which was included in the August 2023 sale of the Competitive Contracted Renewables Portfolio and Flat Ridge 2 which was sold in November 2022.

Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT. PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and

SWEPCo. Under the TCA, AEPSC is responsible for monitoring the reliability of their transmission systems and administering the OATT. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT. Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services.

The charges discussed above are recorded in Other Operation expenses on the statements of income. AEPTCo recorded affiliated transmission revenues in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues section below for amounts related to these transactions.

The following table shows the net transmission service charges recorded by the Registrant Subsidiaries:

	Years Ended December 31,		
Company	**2023**	**2022**	**2021**
		(in millions)	
AEP Texas	$ 28.7	$ 28.5	$ 28.0
APCo	365.1	345.1	302.0
I&M	226.2	220.8	186.7
OPCo	665.3	608.2	508.9
PSO	100.1	110.8	94.7
SWEPCo	49.2	62.1	56.2

Affiliated Revenues

The tables below represent revenues from affiliates, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries. Related party revenues are shown in Sales to AEP Affiliates, Provision for Refund - Affiliated and Other Revenues - Affiliated, respectively, on the Registrant Subsidiaries' statements of income.

Related Party Revenues	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Year Ended December 31, 2023							
Direct Sales to East Affiliates	$ —	$ —	$ 158.7	$ —	$ —	$ —	$ —
Transmission Revenues	—	1,304.0	70.9	(11.1)	3.2	—	45.3
Barging, Urea Transloading and Other Transportation Services	—	—	—	59.0	—	—	—
Other Revenues	4.9	13.8	9.7	9.9	27.9	1.2	1.5
Total Affiliated Revenues	$ 4.9	$ 1,317.8	$ 239.3	$ 57.8	$ 31.1	$ 1.2	$ 46.8

Related Party Revenues	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Year Ended December 31, 2022							
Direct Sales to East Affiliates	$ —	$ —	$ 169.7	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	1.3
Transmission Revenues	—	1,276.4	77.5	7.7	(3.6)	—	51.5
Barging, Urea Transloading and Other Transportation Services	—	—	—	54.1	—	—	—
Other Revenues	3.5	7.4	8.9	7.8	22.4	2.9	1.1
Total Affiliated Revenues	$ 3.5	$ 1,283.8	$ 256.1	$ 69.6	$ 18.8	$ 2.9	$ 53.9

Related Party Revenues	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Year Ended December 31, 2021							
Direct Sales to East Affiliates	$ —	$ —	$ 128.6	$ —	$ —	$ —	$ —
Transmission Revenues	—	1,136.1	60.3	(2.5)	(1.1)	—	39.6
Barging, Urea Transloading and Other Transportation Services	—	—	—	54.0	—	—	—
Other Revenues	3.9	17.8	9.0	6.3	25.9	4.2	1.4
Total Affiliated Revenues	$ 3.9	$ 1,153.9	$ 197.9	$ 57.8	$ 24.8	$ 4.2	$ 41.0

17. VARIABLE INTEREST ENTITIES AND EQUITY METHOD INVESTMENTS

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

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

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

Consolidated Variable Interests Entities

Sabine (Applies to AEP and SWEPCo)

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2023, 2022 and 2021 were $101 million, $168 million and $162 million, respectively. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased, which resulted in a decrease in billings in 2023 as compared to 2022. See "Pirkey Plant and Related Fuel Operations" section of Note 5 for additional information. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $155 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon completion of reclamation. Pirkey Plant was retired in March 2023 and the mine end-of-life has been adjusted accordingly. Reclamation is expected to be complete by 2037 at an estimated cost of $144 million. Actual reclamation costs could vary due to inflation and scope changes to the mine reclamation. SWEPCo recovers these costs through its fuel clauses. As of December 31, 2023, SWEPCo has recorded $134 million of mine reclamation costs in ARO and $34 million in Accounts Payable - Affiliated Companies for collected reclamation costs that have been billed to SWEPCo. SWEPCo has collected $92 million through a rider for reclamation costs. The remaining ARO of $76 million is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

DCC Fuel (Applies to AEP and I&M)

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2023, 2022 and 2021 were $97 million, $84 million and $91 million, respectively. The leases were recorded as finance leases on I&M's balance sheets as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The finance leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding (Applies to AEP and AEP Texas)

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to restructuring legislation in Texas. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. As of December 31, 2023 and 2022, $72 million and $70 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, on the balance sheets. The securitized bonds included in Long-term Debt - Nonaffiliated were immaterial and $71 million as of December 31, 2023 and 2022, respectively, on the balance sheets. Transition Funding has securitized transition assets of $64 million and $125 million as of December 31, 2023 and 2022, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under-recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Restoration Funding (Applies to AEP and AEP Texas)

Restoration Funding was formed for the sole purpose of issuing and servicing securitization bonds related to storm restoration of AEP Texas' distribution system primarily due to damage caused by Hurricane Harvey. Management has concluded that AEP Texas is the primary beneficiary of Restoration Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Restoration Funding. As of December 31, 2023 and 2022, $24 million and $24 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $126 million and $150 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Restoration Funding has securitized assets of $139 million and $161 million as of December 31, 2023 and 2022, respectively, which are presented separately on the face of the balance sheets. The securitized restoration assets represent the right to impose and collect Texas storm restoration costs from customers receiving electric transmission or distribution service from AEP Texas under-recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Restoration Funding's securitized assets and remits all related amounts collected from customers to Restoration Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Restoration Funding's assets and liabilities on the balance sheets.

Appalachian Consumer Rate Relief Funding (Applies to AEP and APCo)

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. As of December 31, 2023 and 2022, $27 million and $26 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $120 million and $147 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $133 million and $160 million as of December 31, 2023 and 2022, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit (Applies to AEP)

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 35% of AEP Credit's short-term borrowing needs in excess of third-party financings. Any third-party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that

AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 14.

EIS (Applies to AEP)

AEP's subsidiaries participate in one protected cell of EIS for seven lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third-parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2023, 2022 and 2021 was $34 million, $31 million and $30 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy (Applies to AEP)

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. Transource Energy's activities consist of the development, construction and operation of FERC-regulated transmission assets in Missouri, West Virginia, Pennsylvania, Maryland and Oklahoma. Transource Energy has a credit facility agreement where borrowings are loaned through intercompany lending agreements to its subsidiaries. The creditor to the agreement has no recourse to the general credit of AEP. Transource Energy's credit facility agreement contains certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

Competitive Contracted Renewables (Applies to AEP)

As of December 31, 2023, Apple Blossom, Black Oak, Santa Rita East and Dry Lake are no longer consolidated VIEs due to the sale of the Competitive Contracted Renewables Portfolio. See the table below for the classification of assets and liabilities on the balance sheets. As of December 31, 2022, nonaffiliated interests in Apple Blossom and Black Oak, Santa Rita East and Dry Lake were $94 million, $58 million and $34 million, respectively, presented in Noncontrolling Interests on the balance sheets. The results of operations for these interests for the years ended December 31, 2023, 2022 and 2021 were not material to the AEP statements of income.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

December 31, 2023

	Consolidated VIEs							
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$ 4.2	$ 81.9	$ 25.5	$ 27.5	$ 13.3	$ 1,208.8	$ 205.3	$ 36.9
Net Property, Plant and Equipment	—	153.8	—	—	—	—	—	533.4
Other Noncurrent Assets	150.7	81.7	71.4 (a)	145.6 (b)	138.2 (c)	9.6	—	5.1
Total Assets	$ 154.9	$ 317.4	$ 96.9	$ 173.1	$ 151.5	$ 1,218.4	$ 205.3	$ 575.4
LIABILITIES AND EQUITY								
Current Liabilities	$ 19.9	$ 81.7	$ 75.5	$ 36.8	$ 29.9	$ 1,155.0	$ 49.2	$ 45.3
Noncurrent Liabilities	134.8	235.7	17.0	135.1	119.7	0.9	91.7	241.5
Equity	0.2	—	4.4	1.2	1.9	62.5	64.4	288.6
Total Liabilities and Equity	$ 154.9	$ 317.4	$ 96.9	$ 173.1	$ 151.5	$ 1,218.4	$ 205.3	$ 575.4

(a) Includes an intercompany item eliminated in consolidation of $8 million.
(b) Includes an intercompany item eliminated in consolidation of $6 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2022

	Registrant Subsidiaries (in millions)				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**AEP Texas Restoration Funding**	**APCo Appalachian Consumer Rate Relief Funding**
ASSETS					
Current Assets	$ 108.3	$ 90.2	$ 27.0	$ 21.1	$ 13.5
Net Property, Plant and Equipment	7.2	179.1	—	—	—
Other Noncurrent Assets	130.0	94.0	140.9 (a)	168.8 (b)	164.6 (c)
Total Assets	$ 245.5	$ 363.3	$ 167.9	$ 189.9	$ 178.1
LIABILITIES AND EQUITY					
Current Liabilities	$ 25.4	$ 90.0	$ 73.2	$ 31.3	$ 29.3
Noncurrent Liabilities	219.4	273.3	90.4	157.4	146.9
Equity	0.7	—	4.3	1.2	1.9
Total Liabilities and Equity	$ 245.5	$ 363.3	$ 167.9	$ 189.9	$ 178.1

(a) Includes an intercompany item eliminated in consolidation of $16 million.
(b) Includes an intercompany item eliminated in consolidation of $7 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2022

	Other Consolidated VIEs (in millions)					
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Apple Blossom and Black Oak**	**Santa Rita East**	**Dry Lake**
ASSETS						
Current Assets	$ 1,181.0	$ 194.5	$ 23.5	$ 8.3	$ 21.3	$ 4.0
Net Property, Plant and Equipment	—	—	482.3	216.5	421.6	142.6
Other Noncurrent Assets	9.0	0.3	2.7	13.6	0.1	0.3
Total Assets	$ 1,190.0	$ 194.8	$ 508.5	$ 238.4	$ 443.0	$ 146.9
LIABILITIES AND EQUITY						
Current Liabilities	$ 1,087.8	$ 46.4	$ 22.8	$ 4.5	$ 9.6	$ 1.0
Noncurrent Liabilities	0.9	79.1	218.6	5.4	7.3	0.7
Equity	101.3	69.3	267.1	228.5	426.1	145.2
Total Liabilities and Equity	$ 1,190.0	$ 194.8	$ 508.5	$ 238.4	$ 443.0	$ 146.9

Non-Consolidated Significant Variable Interests

DHLC (Applies to AEP and SWEPCo)

DHLC is a mining operator which previously sold 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee earned by DHLC. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining. SWEPCo's total billings from DHLC for the years ended December 31, 2023 and 2022 were not material, and for the year ended December 31, 2021 was $47 million. DHLC paid dividends of $1 million, $25 million, and $0 to SWEPCo for the years ended December 31, 2023, 2022 and 2021, respectively. SWEPCo does not have the power to control decision making that significantly impacts the economic performance of DHLC because such power is shared with CLECO. As a result, SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although it holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2023		2022	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	0.4	0.4	0.4	0.4
SWEPCo's Share of Obligations	—	19.2	—	36.8
Total Investment in DHLC	$ 8.0	$ 27.2	$ 8.0	$ 44.8

OVEC (Applies to AEP and OPCo)

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2023, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and are obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2023 and 2022, OVEC's outstanding indebtedness was approximately $1.1 billion and $1.1 billion, respectively. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and its subsidiary each hold a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors of OVEC and the representation of the sponsoring companies on the Operating Committee under the intercompany power agreement.

AEP's investment in OVEC was:

	December 31,			
	2023		2022	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Share of OVEC Debt (a)	—	465.3	—	478.2
Total Investment in OVEC	$ 4.4	$ 469.7	$ 4.4	$ 482.6

(a) Based on the Registrants' power participation ratios, APCo, I&M and OPCo's share of OVEC debt was $168 million, $84 million and $213 million as of December 31, 2023, respectively and $173 million, $86 million and $219 million as of December 31, 2022, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity, Fuel and Other Consumables Used for Electric Generation and Purchased Electricity for Resale on the statements of income and is shown in the table below:

	Years Ended December 31,		
Company	**2023**	**2022**	**2021**
		(in millions)	
APCo	$ 121.8	$ 119.3	$ 104.3
I&M	60.9	59.7	52.2
OPCo	154.7	151.8	133.0

AEPSC (Applies to Registrant Subsidiaries)

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct-charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	**2023**	**2022**	**2021**
		(in millions)	
AEP Texas	$ 228.5	$ 236.8	$ 206.9
AEPTCo	269.9	286.6	267.1
APCo	324.9	347.5	313.3
I&M	178.4	192.4	200.9
OPCo	269.5	272.5	234.9
PSO	138.6	142.3	123.7
SWEPCo	185.1	192.5	168.6

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

	December 31,			
	2023		**2022**	
Company	**As Reported on the Balance Sheet**	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
		(in millions)		
AEP Texas	$ 15.1	$ 15.1	$ 27.8	$ 27.8
AEPTCo	17.9	17.9	31.6	31.6
APCo	21.1	21.1	41.5	41.5
I&M	14.3	14.3	27.7	27.7
OPCo	19.0	19.0	31.1	31.1
PSO	10.6	10.6	17.7	17.7
SWEPCo	12.7	12.7	23.8	23.8

AEGCo (Applies to I&M)

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Units 1 and 2. AEGCo sells its portion of the output from the Rockport Plant to I&M. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2023, 2022 and 2021 were $181 million, $242 million and $218 million, respectively. The carrying amounts of I&M's liabilities associated with AEGCo as of December 31, 2023 and 2022 were $15 million and $17 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Significant Equity Method Investment in Unconsolidated Entities (Applies to AEP)

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

AEP Wind Holdings, LLC

As of December 31, 2023, AEP no longer owns interests in four joint ventures due to the sale of the Competitive Contracted Renewables Portfolio. Previously held by AEP Wind Holdings, LLC, the interests were accounted for under the equity method. As of December 31, 2022, AEP's carrying value of the investment in the joint ventures was $247 million and the difference between AEP's carrying value and the amount of underlying equity in net assets was $62 million. The investment included amounts recognized in AOCI related to interest rate cash flow hedges. AEP's equity losses associated with the joint venture wind farms were $278 thousand, $194 million and $12 million for the years ended December 31, 2023, 2022 and 2021, respectively. The PTCs attributable to the joint ventures for the years ended December 31, 2023, 2022 and 2021 were not material, which were recorded in Income Tax Expense (Benefit) on the statements of income. See the "Disposition of the Competitive Contracted Renewables Portfolio" and "Impairments" sections of Note 7 for additional information.

ETT

ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. BHE, a nonaffiliated entity, holds a 50% membership interest in ETT and AEP Transmission Holdco holds a 50% membership interest in ETT. As a result, AEP, through its wholly-owned subsidiary, holds a 50% membership interest in ETT. As of December 31, 2023 and 2022, AEP's investment in ETT was $811 million and $762 million, respectively. AEP's equity earnings associated with ETT were $74 million, $74 million and $66 million for the years ended December 31, 2023, 2022 and 2021, respectively.

18. PROPERTY, PLANT AND EQUIPMENT

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

Property, Plant and Equipment is shown functionally on the face of the balance sheets. The following tables include the total plant balances as of December 31, 2023 and 2022:

December 31, 2023	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 23,862.7	(a)	$ —	$ —	$ 7,041.3	$ 5,588.7	$ —	$ 2,695.5	$ 4,790.7	(a)
Transmission	35,903.6		6,812.6	13,723.9	4,711.8	1,906.4	3,395.1	1,228.3	2,660.6	
Distribution	28,989.9		5,798.8	—	5,176.6	3,254.0	6,839.4	3,450.8	2,824.1	
Other	5,986.1		1,142.9	501.2	943.7	856.8	1,114.4	502.7	544.1	
CWIP	5,480.6	(a)	904.6	1,563.7	709.2	294.1	654.0	313.7	555.8	(a)
Less: Accumulated Depreciation	24,093.8		1,886.7	1,291.4	5,684.0	4,353.7	2,712.7	2,083.6	2,840.8	
Total Regulated Property, Plant and Equipment - Net	76,129.1		12,772.2	14,497.4	12,898.6	7,546.3	9,290.2	6,107.4	8,534.5	
Nonregulated Property, Plant and Equipment - Net	564.3		1.8	0.3	32.9	82.7	9.7	4.9	23.9	
Total Property, Plant and Equipment - Net	$ 76,693.4		$ 12,774.0	$ 14,497.7	$ 12,931.5	$ 7,629.0	$ 9,299.9	$ 6,112.3	$ 8,558.4	

December 31, 2022	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 23,759.7	(a)	$ —	$ —	$ 6,776.8	$ 5,534.6	$ —	$ 2,394.8	$ 5,476.2	(a)
Transmission	33,221.7		6,301.5	12,335.4	4,482.8	1,842.2	3,198.6	1,164.4	2,479.8	
Distribution	27,138.8		5,312.8	—	4,933.0	3,024.7	6,450.3	3,216.4	2,659.6	
Other	5,528.9		1,020.4	476.6	849.2	796.1	1,040.6	466.0	582.6	
CWIP	4,776.4	(a)	805.2	1,554.7	705.3	253.0	474.3	219.3	369.5	(a)
Less: Accumulated Depreciation	23,118.0		1,759.5	1,027.1	5,397.3	4,117.8	2,564.3	1,839.4	3,314.8	
Total Regulated Property, Plant and Equipment - Net	71,307.5		11,680.4	13,339.6	12,349.8	7,332.8	8,599.5	5,621.5	8,252.9	
Nonregulated Property, Plant and Equipment - Net	2,031.6		1.2	0.3	29.4	78.7	9.8	5.0	9.3	
Total Property, Plant and Equipment - Net	$ 73,339.1		$ 11,681.6	$ 13,339.9	$ 12,379.2	$ 7,411.5	$ 8,609.3	$ 5,626.5	$ 8,262.2	

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

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

Functional Class of Property	2023 Annual Composite Depreciation Rate Ranges	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate Ranges	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate Ranges	2021 Depreciable Life Ranges (in years)
Generation	2.7% - 4.7%	20 - 162	2.7% - 7.6%	20 - 132	2.7% - 7.8%	20 - 132
Transmission	2.0% - 2.7%	15 - 78	2.0% - 2.7%	24 - 75	2.0% - 2.6%	15 - 75
Distribution	2.9% - 3.6%	7 - 85	2.7% - 3.6%	7 - 78	2.8% - 3.6%	7 - 80
Other	3.8% - 9.1%	5 - 75	3.1% - 14.4%	5 - 75	3.0% - 12.5%	5 - 75

AEP Texas

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Transmission	2.2%	50 - 75	2.2%	50 - 75	2.2%	50 - 75
Distribution	2.9%	7 - 70	2.9%	7 - 70	2.9%	7 - 70
Other	6.0%	5 - 50	6.2%	5 - 50	5.8%	5 - 50

AEPTCo

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Transmission	2.6%	24 - 78	2.6%	24 - 75	2.5%	24 - 75
Other	7.0%	5 - 58	6.6%	5 - 56	6.7%	5 - 56

APCo

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Generation	3.3%	35 - 162	3.6%	35 - 118	3.6%	35 - 118
Transmission	2.3%	15 - 78	2.2%	24 - 75	2.1%	15 - 75
Distribution	3.6%	12 - 60	3.6%	12 - 57	3.5%	12 - 57
Other	7.4%	5 - 55	7.3%	5 - 55	8.5%	5 - 55

I&M

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Generation	4.7%	20 - 132	4.9%	20 - 132	4.7%	20 - 132
Transmission	2.5%	44 - 67	2.5%	44 - 67	2.4%	45 - 70
Distribution	2.9%	14 - 71	3.1%	14 - 71	3.4%	14 - 71
Other	9.1%	5 - 45	10.1%	5 - 45	9.0%	5 - 51

OPCo

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	3.1%	11 - 70	2.7%	11 - 70	2.9%	11 - 70
Other	6.4%	5 - 50	6.1%	5 - 50	6.1%	5 - 50

PSO

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Generation	3.0%	25 - 75	3.1%	30 - 75	2.8%	30 - 75
Transmission	2.6%	41 - 75	2.5%	42 - 75	2.4%	42 - 75
Distribution	2.9%	15 - 85	2.9%	15 - 78	2.9%	15 - 78
Other	6.8%	5 - 58	6.8%	5 - 56	6.1%	5 - 56

SWEPCo

Functional Class of Property	2023 Annual Composite Depreciation Rate	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)
Generation	2.9%	30 - 65	2.7%	30 - 65	2.7%	30 - 65
Transmission	2.2%	46 - 70	2.3%	44 - 70	2.4%	49 - 74
Distribution	2.9%	7 - 75	2.9%	15 - 75	2.8%	15 - 80
Other	8.5%	5 - 58	9.0%	5 - 57	8.6%	5 - 58

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP. The Registrants' depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property for 2023, 2022 and 2021.

Functional Class of Property	2023 Annual Composite Depreciation Rate Ranges	2023 Depreciable Life Ranges (in years)	2022 Annual Composite Depreciation Rate Ranges	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate Ranges	2021 Depreciable Life Ranges (in years)
Generation	4.8% - 6.7%	10 - 61	3.8% - 8.7%	3 - 61	3.8% - 10.4%	10 - 59
Transmission	2.5%	62	2.8%	10 - 62	2.6%	30 - 40
Distribution	NA	NA	NA	NA	NA	NA
Other	10.6%	5 - 35 (a)	25.2%	5 - 35 (a)	16.5%	5 - 35 (a)

(a) In 2020, management announced plans to retire the Pirkey Plant in 2023 and the related depreciable lives have been adjusted accordingly. Pirkey Plant was retired in March 2023. See "Coal-Fired Generation Plants" of Note 5 for additional information.
NA Not applicable.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants recorded the following revisions to ARO estimates as of December 31, 2023 and 2022:

- As of December 31, 2023 and 2022, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $2.11 billion and $2 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2023 and 2022, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $3.51 billion and $3.01 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.
- In September 2022, APCo recorded a $14 million revision due to an increase in estimated ash pond closure costs at the Amos Plant.
- In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Traverse assets in proportion to their undivided ownership interests. Traverse was placed in-service in March 2022. As a result, PSO and SWEPCo incurred additional ARO liabilities of $13 million and $15 million, respectively. See the "North Central Wind Energy Facilities" section of Note 7 for additional information.
- In March 2022, SWEPCo recorded a $13 million revision due to an increase in estimated ash pond closure costs at the Pirkey Plant and the Welsh Plant. In June 2022, SWEPCo recorded a $16 million revision due to an increase in estimated reclamation costs at Sabine. In September 2022, SWEPCo recorded a $14 million revision due to an

increase in estimated landfill closure costs at Pirkey Plant. In November 2022, SWEPCo recorded an additional $7 million revision related to an increase in estimated reclamation costs at Sabine.

- In August 2023, AEP completed the sale of its competitive contracted renewables portfolio to a nonaffiliated party and settled ARO liabilities of $31 million. See "Disposition of the Competitive Contracted Renewables Portfolio" section of Note 7 for additional information.
- In December 2023, SWEPCo recorded a $32 million revision related to an increase in estimated reclamation costs at Sabine. Additionally in 2023, SWEPCo settled $50 million of costs related to closure/reclamation work performed due to the recent retirements of the Pirkey Plant and Dolet Hills Power Station. See "Coal-Fired Generation Plants" section of Note 5 for additional information.
- In 2023, APCo recorded revisions of $27 million primarily due to an increase in estimated asbestos costs at several plants.

The following is a reconciliation of the 2023 and 2022 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2022	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2023
			(in millions)			
AEP(b)(c)(d)(e)(f)(g)	$ 2,943.6	$ 116.3	$ 38.9	$ (130.6)	$ 63.0	$ 3,031.2
AEP Texas (b)(e)	4.5	0.2	—	(0.3)	0.1	4.5
APCo (b)(e)	427.7	16.8	16.1	(23.1)	26.5	464.0
I&M (b)(c)(e)	2,028.1	74.8	4.8	(3.7)	2.0	2,106.0
OPCo (e)	5.0	0.2	—	(3.1)	—	2.1
PSO (b)(e)(g)	75.7	4.7	5.8	(1.2)	(0.8)	84.2
SWEPCo (b)(d)(e)(g)	280.9	13.7	7.5	(55.0)	34.5	281.6

Company	ARO as of December 31, 2021	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2022
			(in millions)			
AEP (b)(c)(d)(e)(f)(g)	$ 2,741.7	$ 111.2	$ 37.4	$ (47.0)	$ 100.3	$ 2,943.6
AEP Texas (b)(e)	4.4	0.3	—	(0.2)	—	4.5
APCo (b)(e)	404.6	15.8	3.0	(12.7)	17.0	427.7
I&M (b)(c)(e)	1,946.3	71.5	3.2	(0.6)	7.7	2,028.1
OPCo (e)	1.9	0.2	3.0	(0.1)	—	5.0
PSO (b)(e)(g)	57.6	4.1	12.8	(0.7)	1.9	75.7
SWEPCo (b)(d)(e)(g)	222.7	11.9	15.4	(25.8)	56.7	280.9

(a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $2.11 billion and $2 billion as of December 31, 2023 and 2022, respectively.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Includes ARO related to solar farms.
(g) Includes ARO related to wind farms.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2023	2022	2021
		(in millions)	
AEP	$ 174.9	$ 133.7	$ 139.7
AEP Texas	28.4	19.7	21.5
AEPTCo	83.2	70.7	67.2
APCo	11.9	11.7	15.6
I&M	10.9	9.8	12.8
OPCo	17.1	13.9	10.8
PSO	8.4	1.5	2.4
SWEPCo	11.5	4.9	7.0

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

Company	Years Ended December 31, 2023	2022	2021
		(in millions)	
AEP	$ 117.3	$ 63.0	$ 53.8
AEP Texas	23.4	11.5	10.5
AEPTCo	31.4	22.4	21.0
APCo	14.1	6.5	7.5
I&M	7.7	5.7	5.1
OPCo	14.0	6.7	4.7
PSO	5.2	2.7	0.7
SWEPCo	9.8	4.3	3.0

Jointly-owned Electric Facilities (Applies to AEP, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2023		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 402.8	$ 1.6	$ 167.5
Pirkey Plant, Unit 1 (a)(f)	Lignite	85.9 %	—	—	—
Turk Generating Plant (a)(g)	Coal	73.3 %	1,504.0	10.1	323.3
Total			$ 1,906.8	$ 11.7	$ 490.8
I&M					
Rockport Generating Plant (b)(c)	Coal	50.0 %	$ 1,341.4	$ 7.9	$ 1,018.9
PSO					
North Central Wind Energy Facilities (d)(e)	Wind	45.5 %	$ 906.3	$ 2.4	$ 54.1
SWEPCo					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 402.8	$ 1.6	$ 167.5
Pirkey Plant, Unit 1 (a)(f)	Lignite	85.9 %	—	—	—
Turk Generating Plant (a)(g)	Coal	73.3 %	1,504.0	10.1	323.3
North Central Wind Energy Facilities (d)(e)	Wind	54.5 %	1,086.3	2.9	67.9
Total			$ 2,993.1	$ 14.6	$ 558.7

			Registrant's Share as of December 31, 2022		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 382.9	$ 16.4	$ 149.4
Pirkey Plant, Unit 1 (a)	Lignite	85.9 %	632.0	—	632.0
Turk Generating Plant (a)	Coal	73.3 %	1,611.1	5.1	314.7
Total			$ 2,626.0	$ 21.5	$ 1,096.1
I&M					
Rockport Generating Plant (b)(c)	Coal	50.0 %	$ 1,357.4	$ 9.2	$ 905.1
PSO					
North Central Wind Energy Facilities (d)(e)	Wind	45.5 %	$ 889.3	$ 9.1	$ 28.1
SWEPCo					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 382.9	$ 16.4	$ 149.4
Pirkey Plant, Unit 1 (a)	Lignite	85.9 %	632.0	—	632.0
Turk Generating Plant (a)	Coal	73.3 %	1,611.1	5.1	314.7
North Central Wind Energy Facilities (d)(e)	Wind	54.5 %	1,066.8	10.1	35.2
Total			$ 3,692.8	$ 31.6	$ 1,131.3

(a) Operated by SWEPCo.
(b) Operated by I&M.
(c) AEGCo owns 50%.
(d) Operated by PSO.
(e) PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively.
(f) Pirkey Plant was retired in March 2023. See "Coal-Fired Generation Plants" of Note 5 for additional information.
(g) Includes impact of regulatory disallowance of AFUDC. See "2012 Texas Base Rate Case" section of Note 4 for additional information.

19. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The table below represents AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 2023						
	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	$ 4,479.3	$ 2,609.1	$ —	$ —	$ —	$ —	$ 7,088.4
Commercial Revenues	2,678.8	1,497.2	—	—	—	—	4,176.0
Industrial Revenues (a)	2,748.2	642.1	—	—	—	(0.9)	3,389.4
Other Retail Revenues	242.7	50.7	—	—	—	—	293.4
Total Retail Revenues	10,149.0	4,799.1	—	—	—	(0.9)	14,947.2
Wholesale and Competitive Retail Revenues:							
Generation Revenues	662.5	—	—	111.3	—	—	773.8
Transmission Revenues (b)	444.0	701.6	1,748.9	—	—	(1,418.3)	1,476.2
Renewable Generation Revenues (a)	—	—	—	80.6	—	(6.7)	73.9
Retail, Trading and Marketing Revenues (c)	—	—	—	1,836.2	0.6	(82.2)	1,754.6
Total Wholesale and Competitive Retail Revenues	1,106.5	701.6	1,748.9	2,028.1	0.6	(1,507.2)	4,078.5
Other Revenues from Contracts with Customers (d)	204.4	208.1	16.8	8.6	151.5	(160.3)	429.1
Total Revenues from Contracts with Customers	11,459.9	5,708.8	1,765.7	2,036.7	152.1	(1,668.4)	19,454.8
Other Revenues:							
Alternative Revenue Programs (e)	(35.0)	(19.5)	(37.1)	—	—	(25.5)	(117.1)
Other Revenues (a) (f)	24.6	24.0	(0.1)	(404.5)	15.9	(15.3)	(355.4)
Total Other Revenues	(10.4)	4.5	(37.2)	(404.5)	15.9	(40.8)	(472.5)
Total Revenues	$ 11,449.5	$ 5,713.3	$ 1,728.5	$ 1,632.2	$ 168.0	$ (1,709.2)	$ 18,982.3

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.5 billion and Vertically Integrated Utilities was $205 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $82 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $100 million. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(f) Generation & Marketing includes economic hedge activity.

	Year Ended December 31, 2022						
	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	$ 4,498.6	$ 2,497.3	$ —	$ —	$ —	$ —	$ 6,995.9
Commercial Revenues	2,576.5	1,365.2	—	—	—	—	3,941.7
Industrial Revenues (a)	2,543.8	711.3	—	—	—	(0.9)	3,254.2
Other Retail Revenues	212.2	49.1	—	—	—	—	261.3
Total Retail Revenues	9,831.1	4,622.9	—	—	—	(0.9)	14,453.1
Wholesale and Competitive Retail Revenues:							
Generation Revenues	958.3	—	—	271.2	—	—	1,229.5
Transmission Revenues (b)	442.8	650.0	1,700.6	—	—	(1,413.2)	1,380.2
Renewable Generation Revenues (a)	—	—	—	129.1	—	(8.0)	121.1
Retail, Trading and Marketing Revenues (a)	—	—	—	1,713.2	6.9	(10.1)	1,710.0
Total Wholesale and Competitive Retail Revenues	1,401.1	650.0	1,700.6	2,113.5	6.9	(1,431.3)	4,440.8
Other Revenues from Contracts with Customers (c)	241.1	247.3	8.2	12.1	93.9	(104.8)	497.8
Total Revenues from Contracts with Customers	11,473.3	5,520.2	1,708.8	2,125.6	100.8	(1,537.0)	19,391.7
Other Revenues:							
Alternative Revenue Programs (d)	3.8	(26.8)	(31.8)	—	—	(57.7)	(112.5)
Other Revenues (a) (e)	0.4	18.6	—	341.3	9.1	(9.1)	360.3
Total Other Revenues	4.2	(8.2)	(31.8)	341.3	9.1	(66.8)	247.8
Total Revenues	$ 11,477.5	$ 5,512.0	$ 1,677.0	$ 2,466.9	$ 109.9	$ (1,603.8)	$ 19,639.5

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.3 billion. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $59 million. The remaining affiliated amounts were immaterial.

(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(e) Generation & Marketing includes economic hedge activity.

	Year Ended December 31, 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	$ 3,952.6	$ 2,138.2	$ —	$ —	$ —	$ —	$ 6,090.8
Commercial Revenues	2,208.5	1,081.2	—	—	—	—	3,289.7
Industrial Revenues	2,168.2	395.2	—	—	—	(0.8)	2,562.6
Other Retail Revenues	170.6	43.9	—	—	—	—	214.5
Total Retail Revenues	8,499.9	3,658.5	—	—	—	(0.8)	12,157.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	942.6	—	—	137.9	—	—	1,080.5
Transmission Revenues (a)	355.5	572.4	1,456.4	—	—	(1,206.0)	1,178.3
Renewable Generation Revenues (b)	—	—	—	86.9	—	(3.6)	83.3
Retail, Trading and Marketing Revenues (c)	—	—	—	1,722.6	1.4	(51.6)	1,672.4
Total Wholesale and Competitive Retail Revenues	1,298.1	572.4	1,456.4	1,947.4	1.4	(1,261.2)	4,014.5
Other Revenues from Contracts with Customers (b)	187.5	194.2	17.1	7.2	60.1	(115.2)	350.9
Total Revenues from Contracts with Customers	9,985.5	4,425.1	1,473.5	1,954.6	61.5	(1,377.2)	16,523.0
Other Revenues:							
Alternative Revenue Programs (d)	13.5	48.8	52.7	—	—	(73.6)	41.4
Other Revenues (b) (e)	(0.5)	19.0	—	209.1	10.7	(10.7)	227.6
Total Other Revenues	13.0	67.8	52.7	209.1	10.7	(84.3)	269.0
Total Revenues	$ 9,998.5	$ 4,492.9	$ 1,526.2	$ 2,163.7	$ 72.2	$ (1,461.5)	$ 16,792.0

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.1 billion. 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 $52 million. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Generation & Marketing includes economic hedge activity.

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Year Ended December 31, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 655.5	$ —	$ 1,612.9	$ 841.9	$ 1,953.7	$ 831.2	$ 799.5
Commercial Revenues	415.2	—	699.6	575.2	1,082.0	538.8	609.4
Industrial Revenues (a)	145.0	—	778.4	614.2	497.1	423.1	415.9
Other Retail Revenues	35.5	—	106.3	5.0	15.1	112.8	10.1
Total Retail Revenues	1,251.2	—	3,197.2	2,036.3	3,547.9	1,905.9	1,834.9
Wholesale Revenues:							
Generation Revenues (b)	—	—	288.2	327.1	—	11.7	176.9
Transmission Revenues (c)	619.0	1,703.9	181.0	38.6	82.6	37.5	150.8
Total Wholesale Revenues	619.0	1,703.9	469.2	365.7	82.6	49.2	327.7
Other Revenues from Contracts with Customers (d)	35.9	16.7	74.2	120.3	172.3	21.5	29.5
Total Revenues from Contracts with Customers	1,906.1	1,720.6	3,740.6	2,522.3	3,802.8	1,976.6	2,192.1
Other Revenues:							
Alternative Revenue Programs (e)	(4.2)	(48.6)	(20.1)	(10.9)	(15.3)	0.5	(9.4)
Other Revenues (a)	—	—	0.2	24.5	23.9	(0.1)	0.1
Total Other Revenues	(4.2)	(48.6)	(19.9)	13.6	8.6	0.4	(9.3)
Total Revenues	$ 1,901.9	$ 1,672.0	$ 3,720.7	$ 2,535.9	$ 3,811.4	$ 1,977.0	$ 2,182.8

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $159 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.4 billion, APCo was $93 million and SWEPCo was $73 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $68 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

	Year Ended December 31, 2022						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 667.2	$ —	$ 1,558.7	$ 852.4	$ 1,830.2	$ 816.3	$ 820.7
Commercial Revenues	417.5	—	643.4	550.2	947.7	489.2	612.3
Industrial Revenues (a)	139.6	—	664.0	602.9	571.7	372.5	393.5
Other Retail Revenues	35.3	—	87.1	5.0	13.9	102.9	10.1
Total Retail Revenues	1,259.6	—	2,953.2	2,010.5	3,363.5	1,780.9	1,836.6
Wholesale Revenues:							
Generation Revenues (b)	—	—	299.9	490.0	—	26.5	273.2
Transmission Revenues (c)	563.8	1,643.5	167.0	36.8	86.2	39.2	148.7
Total Wholesale Revenues	563.8	1,643.5	466.9	526.8	86.2	65.7	421.9
Other Revenues from Contracts with Customers (d)	24.6	8.2	100.6	122.4	222.4	29.1	24.7
Total Revenues from Contracts with Customers	1,848.0	1,651.7	3,520.7	2,659.7	3,672.1	1,875.7	2,283.2
Other Revenues:							
Alternative Revenue Programs (e)	(1.2)	(27.2)	(1.3)	10.0	(25.6)	(1.0)	1.2
Other Revenues (a)	—	—	0.5	(0.1)	18.6	—	—
Total Other Revenues	(1.2)	(27.2)	(0.8)	9.9	(7.0)	(1.0)	1.2
Total Revenues	$ 1,846.8	$ 1,624.5	$ 3,519.9	$ 2,669.6	$ 3,665.1	$ 1,874.7	$ 2,284.4

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $170 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.3 billion, APCo was $78 million and SWEPCo was $51 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $62 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

	Year Ended December 31, 2021						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 550.3	$ —	$ 1,379.6	$ 805.4	$ 1,587.9	$ 651.9	$ 709.5
Commercial Revenues	358.5	—	556.3	507.2	722.7	378.9	529.3
Industrial Revenues	108.9	—	584.3	557.0	286.3	274.1	344.4
Other Retail Revenues	31.3	—	70.8	5.2	12.6	77.7	10.0
Total Retail Revenues	1,049.0	—	2,591.0	1,874.8	2,609.5	1,382.6	1,593.2
Wholesale Revenues:							
Generation Revenues (a)	—	—	302.7	318.1	—	22.9	386.6
Transmission Revenues (b)	497.5	1,393.9	128.8	33.7	74.9	37.5	122.7
Total Wholesale Revenues	497.5	1,393.9	431.5	351.8	74.9	60.4	509.3
Other Revenues from Contracts with Customers (c)	41.2	17.0	70.4	104.1	153.1	31.3	23.5
Total Revenues from Contracts with Customers	1,587.7	1,410.9	3,092.9	2,330.7	2,837.5	1,474.3	2,126.0
Other Revenues:							
Alternative Revenue Programs (d)	6.1	58.4	12.3	(4.0)	42.6	0.1	5.8
Other Revenues (e)	—	—	—	—	19.0	—	—
Total Other Revenues	6.1	58.4	12.3	(4.0)	61.6	0.1	5.8
Total Revenues	$ 1,593.8	$ 1,469.3	$ 3,105.2	$ 2,326.7	$ 2,899.1	$ 1,474.4	$ 2,131.8

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $129 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.1 billion. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $60 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

AEP has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. AEP subsidiaries elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for AEP's subsidiaries are summarized as follows:

Retail Revenues

AEP's subsidiaries within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments have performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between AEP's subsidiaries and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice. Payments from REPs are due to AEP Texas within 35 days.

Wholesale Revenues - Generation

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments have performance obligations to sell electricity to wholesale customers from generation assets in PJM, SPP and ERCOT. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments also have performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales within the Vertically Integrated Utilities segment are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues tables above.

APCo has a performance obligation to supply wholesale electricity to KGPCo through a PPA. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the Tennessee Regulatory Authority. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues line in the disaggregated revenues tables above.

Wholesale Revenues - Transmission

AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco segments have performance obligations to transmit electricity to wholesale customers through assets owned and operated by AEP subsidiaries. The performance obligation to provide transmission services in PJM, SPP and ERCOT is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP and ERCOT and weekly for PJM.

AEP subsidiaries within the PJM and SPP regions collect revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues tables above. AEP subsidiaries within the ERCOT region collect revenues through a combination of base rates and interim Transmission Costs of Services filings that are approved by the PUCT.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. PSO, SWEPCo and AEPSC are parties to the TCA by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. AEPTCo is a transmission owner within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. Affiliate revenues as a result of the respective TA and the TCA are reflected as Transmission Revenues in the disaggregated revenues tables above.

Marketing, Competitive Retail and Renewable Revenues

AEP's subsidiaries within the Generation & Marketing segment have performance obligations to deliver electricity to competitive retail and wholesale customers. Performance obligations for marketing, competitive retail and renewable offtake sales are satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are primarily variable as they are subject to customer's usage requirements; however, certain contracts mandate a delivery of a set quantity of electricity at a predetermined price, resulting in a fixed performance obligation.

Payment terms under marketing arrangements typically follow standard Edison Electric Institute and International Swaps and Derivatives Association terms, which call for payment in 20 days. Payments for competitive retail and offtake arrangements for renewable assets range from 15 to 60 days and are dependent on the product sold, location and the creditworthiness of customer. Invoices for marketing arrangements, competitive retail and offtake arrangements for renewable assets are issued monthly.

Fixed Performance Obligations (Applies to AEP, APCo and I&M)

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of December 31, 2023. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrants elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2024	2025-2026	2027-2028	After 2028	Total
			(in millions)		
AEP	$ 84.4	$ 167.2	$ 84.4	$ 27.3	$ 363.3
APCo	16.1	32.2	23.2	11.7	83.2
I&M	4.4	8.8	8.8	4.5	26.5

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have any material contract assets as of December 31, 2023 and 2022.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have any material contract liabilities as of December 31, 2023 and 2022.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrants' balance sheets within the Accounts Receivable - Customers line item. The Registrants' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2023 and 2022. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Years Ended December 31,	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2023	$ —	$ 123.2	$ 71.7	$ 44.0	$ 70.1	$ 12.4	$ 27.4
2022	0.1	113.8	64.5	75.3	49.9	18.8	19.1

Contract Costs

Contract costs to obtain or fulfill a contract for AEP subsidiaries within the Generation & Marketing segment are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current and noncurrent assets on the Registrants' balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on the Registrants' income statements. The Registrants did not have material contract costs as of December 31, 2023 and 2022.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing - The Company's common stock is traded principally on the NASDAQ Stock Market under the ticker symbol AEP.

Internet Home Page - Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings - Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
150 Royall St.
Suite 101
Canton, MA 02021
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders - (Stock held in a bank or brokerage account) - When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan - A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/stock.

Financial Community Inquiries - Institutional investors or securities analysts who have questions about the Company should direct inquiries to Darcy Reese, 614-716-2614, dlreese@aep.com; Individual shareholders should contact Rhonda Owens-Paul, 614-716-2819, rkowens-paul@aep.com.

Number of Shareholders - As of February 26, 2024, there were approximately 48,580 registered shareholders and approximately 1,226,106 shareholders holding stock in street name through a bank or broker. There were 526,590,278 shares outstanding as of February 26, 2024.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2023. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at rkowens-paul@AEP.com. A copy of our Form 10-K can also be found by visiting www.AEP.com/investors/financial/sec/.

Executive Leadership Team

Name	Age	Office
Benjamin G.S. Fowke, III	65	President and Interim Chief Executive Officer
Christian T. Beam	55	Executive Vice President - Energy Services
David M. Feinberg	54	Executive Vice President, General Counsel and Secretary
Greg B. Hall	51	Executive Vice President and Chief Commercial Officer
Therace M. Risch	50	Executive Vice President and Chief Information & Technology Officer
Peggy Simmons	46	Executive Vice President - Utilities
Antonio Smyth	47	Executive Vice President - Grid Solutions & Government Affairs
Phillip R. Ulrich	53	Executive Vice President and Chief Human Resources Officer
Charles E. Zebula	63	Executive Vice President and Chief Financial Officer