Appendix A to the
Proxy Statement

American Electric Power

2022 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

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 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.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
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.
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.

Term	Meaning
APSC	Arkansas Public Service Commission.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for rate-making purposes.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
ATM	At-the-Market.
CAA	Clean Air Act.
CARES Act	Coronavirus Aid, Relief, and Economic Security Act signed into law in March 2020.
CCR	Coal Combustion Residual.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
CO_{2e}	Carbon dioxide equivalent.
Conesville Plant	A retired, single unit coal-fired generation plant totaling 651 MW located in Conesville, Ohio. The plant was jointly-owned by AGR and a nonaffiliate.
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.
CWA	Clean Water Act.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII and DCC Fuel XVIII consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	Desert Sky Wind Farm LLC, a 170 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas in which AEP owns a 100% interest.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
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.

Term	Meaning
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.
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).
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
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.
NERC	North American Electric Reliability Corporation.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,484 MWs of wind generation.
NOL	Net operating losses.
NOLC	Net operating loss carryforwards.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.

Term	Meaning
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
ODFA	Oklahoma Development Finance Authority.
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Oklaunion Power Station	A retired, single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant was jointly-owned by AEP Texas, PSO and certain nonaffiliated entities.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PATH-WV	PATH West Virginia Transmission Company, LLC, a joint venture-owned 50% by FirstEnergy and 50% by AEP.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PFD	Proposal for Decision.
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.
PTC	Production Tax Credit.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Racine	A generation plant consisting of two hydroelectric generating units totaling 48 MWs located in Racine, Ohio and formerly owned by AGR. Racine was sold to a nonaffiliate in December 2021.
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.

Term	Meaning
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.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo’s seven wholly-owned, FERC regulated, transmission only electric utilities, 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.
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.
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.
Trent	Trent Wind Farm LLC, a 156 MW wind electricity generation facility located in west Texas in which AEP owns a 100% interest.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.

Term	Meaning
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
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 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.
- The economic impact of increased global trade tensions including the conflict between Russia and Ukraine, 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; 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 or subsidiaries, 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.
- 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, and to recover those costs.
- 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.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.

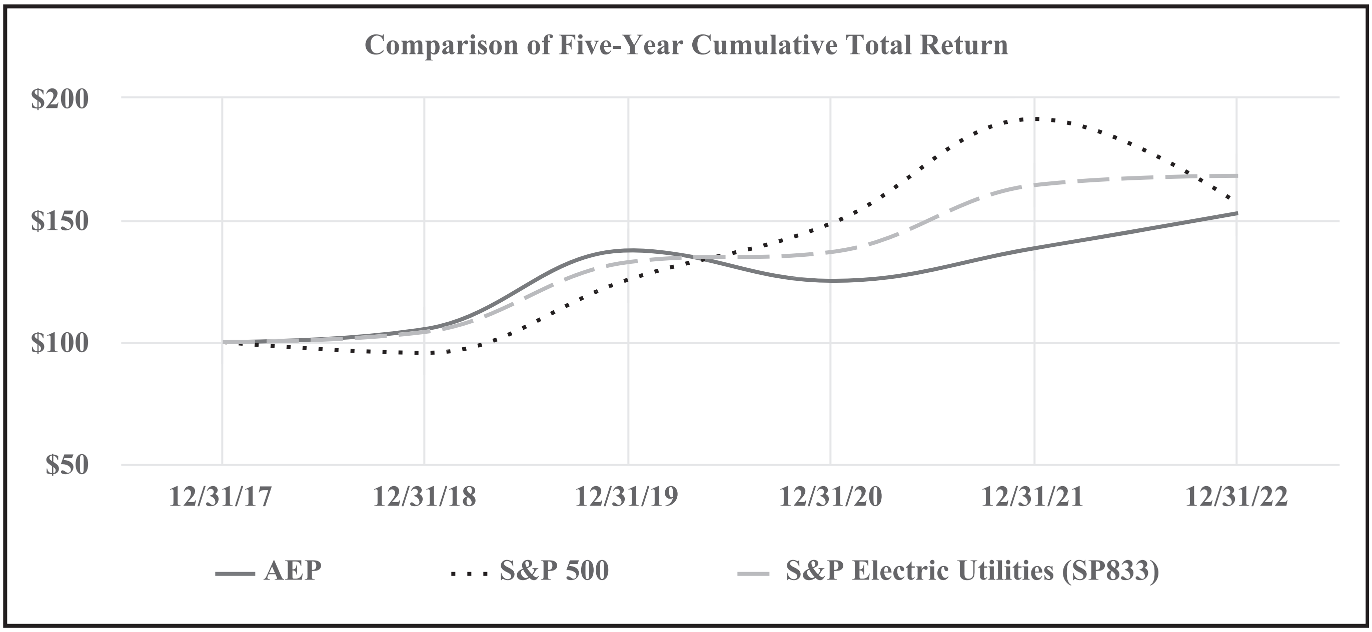
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas.
- The impact of changing expectations and demands of customers, regulators, investors and stakeholders, including heightened emphasis 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, naturally occurring and human-caused fires, cyber-security threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

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

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, 2022, AEP had 51,279 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, 2017 and that all dividends were reinvested.



Source: S&P Dow Jones Indices LLC. Data as of December 31, 2022. 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.

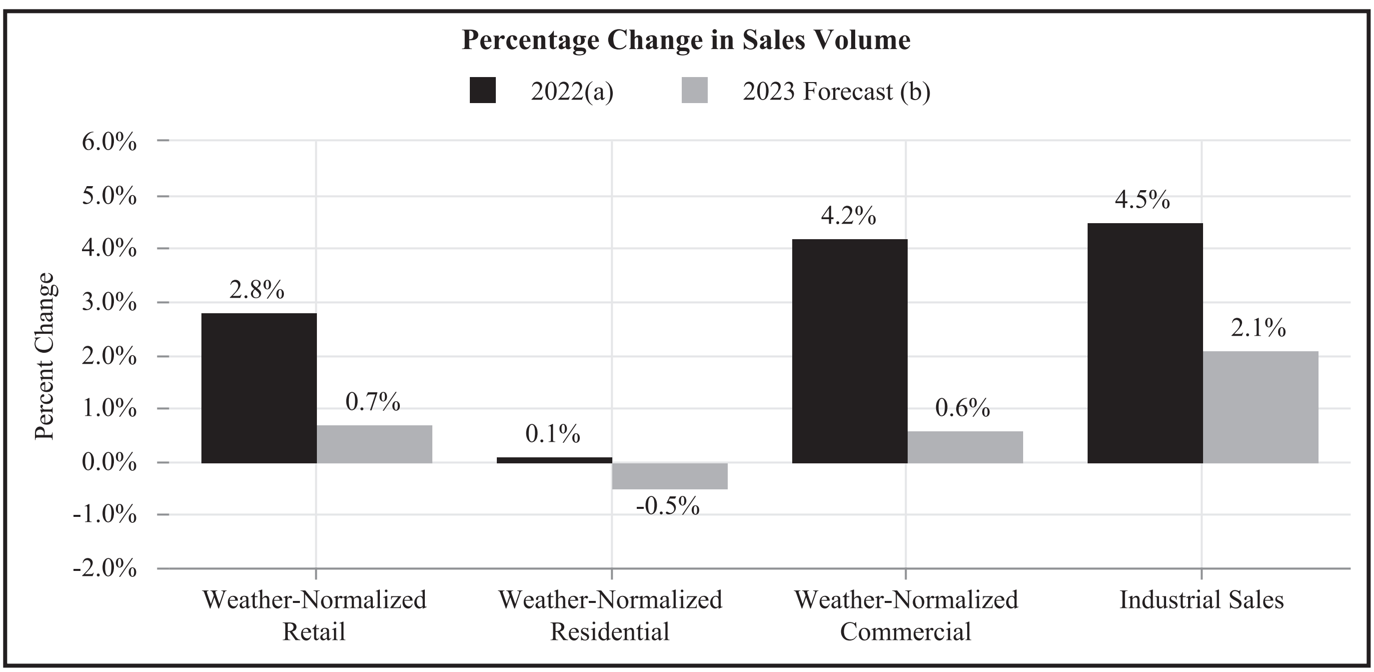
AEP's subsidiaries operate an extensive portfolio of assets including:

- 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 23,500 MWs of regulated owned generating capacity as of December 31, 2022, one of the largest complements of generation in the United States.

Customer Demand

AEP's weather-normalized retail sales volumes for the year ended December 31, 2022 increased by 2.8% from the year ended December 31, 2021. Weather-normalized residential sales increased 0.1% for the year ended December 31, 2022 compared to the year ended December 31, 2021. Weather-normalized commercial sales increased by 4.2% in 2022 compared to 2021. The increase in commercial sales was spread across many sectors. AEP's 2022 industrial sales volumes increased 4.5% compared to 2021. The growth in industrial sales was spread across many industries.

In 2023, AEP anticipates weather-normalized retail sales volumes will increase by 0.7%. Weather-normalized residential sales volumes are projected to decrease by 0.5% in 2023, while weather-normalized commercial sales volumes are projected to increase by 0.6%. Finally, AEP projects the industrial class to increase by 2.1% in 2023.



(a) Percentage change for the year ended December 31, 2022 as compared to the year ended December 31, 2021.
(b) Forecasted percentage change for the year ended December 31, 2023 compared to the year ended December 31, 2022.

Supply Chain Disruption and Inflation

The Registrants have experienced certain supply chain disruptions driven by several factors including staffing and travel issues caused by the COVID-19 pandemic, international tensions including 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 inflation will continue and at what rate. 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.

Strategic Evaluation of AEP Energy

AEP has initiated a strategic evaluation for its ownership in AEP Energy, a wholly-owned retail energy supplier that supplies electricity and/or natural gas 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 736,000 customer accounts as of December 31, 2022. Potential alternatives may include, but are not limited to, continued ownership or a sale of all or a part of AEP Energy. Management has not made a decision regarding the potential alternatives, but expects to complete the strategic evaluation in the first half of 2023.

Regulatory Matters

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

- *2017-2019 Virginia Triennial Review* - In November 2020, the Virginia SCC issued an order on APCo's 2017-2019 Triennial Review filing concluding that APCo earned above its authorized ROE but within its ROE band for the 2017-2019 period, resulting in no refund to customers and no change to APCo base rates on a prospective basis. The Virginia SCC approved a prospective 9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a statutory 140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top). APCo appealed this order and a similar order on reconsideration to the Virginia Supreme Court in March 2021, alleging the Virginia SCC erred in finding that costs associated with asset impairments related to APCo early retirement determinations for certain generation facilities should not be attributed to the 2017-2019 test periods under review and deemed fully recovered in the period recorded. In August 2022, the Virginia Supreme Court agreed with this portion of APCo's appeal and remanded this issue regarding the retired coal-fired plants back to the Virginia SCC for further proceedings. In September 2022, as a result of the Virginia Supreme Court ruling, APCo expensed the remaining $25 million closed coal plant regulatory asset that was previously ordered by the Virginia SCC and recorded a $37 million regulatory asset for previously incurred costs that APCo is expecting to recover as a result of earning below its 2017-2019 authorized ROE band.

  In response to the Virginia Supreme Court's August 2022 opinion, the Virginia SCC initiated remand proceedings and, in December 2022, issued an order that: (a) approved APCo's requested $37 million regulatory asset related to previously incurred costs as a result of APCo earning below its 2017-2019 authorized ROE band, (b) authorized a $28 million annual increase in APCo Virginia base rates effective

October 2022 and (c) approved a rider to recover approximately $48 million related to this APCo Virginia base rate increase for the period January 2021 through September 2022. APCo's 2022 financial statements reflect the impact of the Virginia SCC's December 2022 order.

- *2020-2022 Virginia Triennial Review* - In March 2023, APCo will submit its required Virginia earnings test calculation to the Virginia SCC for the 2020-2022 Triennial Review 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 major storms, the early retirement of fossil fuel generating assets and certain projects necessary to comply with state and federal environmental legislation. As of December 2022, APCo has deferred approximately $38 million related to previously incurred costs as a result of the current estimate that APCo will earn below the bottom of its authorized ROE band during the 2020-2022 Triennial Review period.

  APCo is also required to submit a depreciation study as part of its 2020-2022 Triennial Review filing based on plant in service balances as of December 31, 2022. APCo is required to implement the impacts of this depreciation study effective January 1, 2023 without a corresponding adjustment in customer rates until the first quarter of 2024. While subject to review as part of APCo's 2020-2022 Virginia Triennial Review, a significant change in depreciation rates (either an increase or a decrease) without a corresponding adjustment in Virginia retail rates would impact future net income and cash flows and impact financial condition.

- *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 July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court.

  In March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant. In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. No parties filed a motion for rehearing with the Texas Supreme Court. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court 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. SWEPCo disagrees with the Court of Appeals decision. SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court in November 2021. 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. The Texas Supreme Court requested comments on rehearing by March 1, 2023. If SWEPCo's request for rehearing is denied, the case will be remanded to the PUCT for future proceedings.

  Management does not believe a disallowance of capitalized Turk Plant costs or a revenue refund is probable as of December 31, 2022. However, if SWEPCo is ultimately unable to recover AFUDC in excess of the Texas jurisdictional capital cost cap, it would be expected to result in a pretax net disallowance ranging from $80 million to $90 million. In addition, if AFUDC is ultimately determined to be included in the Texas jurisdictional capital cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $185 million related to revenues collected from February 2013 through December 2022 and such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis.

- In July 2019, Ohio House Bill 6 (HB 6), which offered incentives for power-generating facilities with zero or reduced carbon emissions, was signed into law by the Ohio Governor. HB 6 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 have since pleaded guilty and a criminal trial is proceeding against the other. 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.

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

  In 2019, the FERC approved settlement agreements establishing base ROEs of 9.85% (10.35% inclusive of RTO Incentive adder of 0.5%) and 10% (10.5% inclusive of RTO Incentive adder of 0.5%) for AEP's PJM and SPP transmission-owning subsidiaries, respectively. In 2020, the FERC determined the base ROE for MISO's transmission owning subsidiaries should be 10.02% (10.52% inclusive of RTO Incentive adder of 0.5%).

  If the FERC modifies its RTO Incentive policy, it would be applied, as applicable, to AEP's PJM, SPP and MISO transmission owning subsidiaries on a prospective basis, and could affect future net income and cash flows and impact financial condition. Based on management's preliminary estimates, if a final rule is adopted consistent with the April 2021 supplemental NOPR, it could reduce AEP's pretax income by approximately $35 million to $50 million on an annual basis.

- *FERC RTO Incentive Complaint* - In February 2022, the Office of the Ohio Consumers' Counsel (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 0.5 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. A FERC order on rehearing is expected in 2023. Based on management's preliminary estimates, the December 2022 FERC order is expected to reduce AEP's pretax income by approximately $20 million on an annual basis.

  In July 2021, the FERC issued an order denying Dayton Power and Light's request for a 50 basis point RTO incentive on the basis that its RTO participation was not voluntary, but rather is required by Ohio law. This precedent could have an adverse impact on AEP's Ohio transmission owning subsidiaries. In its February 2022 order on rehearing, the FERC affirmed the decision in its July 2021 order. The case is currently pending appeal at the U.S. Court of Appeals for the Sixth Circuit. In May 2022, the U.S. Court of Appeals for the Sixth Circuit issued an order to hold the appeal in abeyance pending resolution of FERC proceedings on the Office of the Ohio Consumers' Counsels' February 2022 RTO Incentive Complaint.

- *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 October 2021, SWEPCo filed a request with the LPSC for recovery of $145 million in deferred storm costs associated with the three storms. As part of the filing, SWEPCo requested recovery of the carrying charges on the deferred regulatory asset at a weighted average cost of capital through a rider beginning in January 2022. In May 2022, LPSC staff testimony was submitted to the LPSC. In July 2022, SWEPCo filed rebuttal testimony which agreed to make a request for securitization as the LPSC staff had recommended in their testimony. An order is expected in the first quarter of 2023. If any of the storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

- In February 2021, severe winter weather had a significant impact in SPP, resulting in the declaration of Energy Emergency Alert Levels 2 and 3 for the first time in SPP's history. The winter storm increased the demand for natural gas and restricted the available natural gas supply resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. As a result of the severe winter weather, PSO and SWEPCo incurred approximately $1.1 billion of extraordinary fuel costs and purchases of electricity, which were deferred as regulatory assets.

  In April 2021, the OCC approved a waiver for PSO allowing the deferral of the extraordinary fuel and purchases of electricity as regulatory assets, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. Also in April 2021, legislation was enacted in Oklahoma permitting securitized financing of qualified costs from extreme weather events. This legislation provides certain authority to the OCC to approve amounts to be recovered from the issuance of ratepayer-backed securitized bonds issued by the ODFA, an Oklahoma governmental agency. In January 2022, PSO, OCC staff and certain intervenors filed a joint stipulation and settlement agreement with the OCC to approve the securitization of PSO's extraordinary fuel costs and purchases of electricity. In February 2022, the OCC approved the joint stipulation and settlement agreement which included a determination that all of PSO's extraordinary fuel costs and purchases of electricity were prudent and reasonable and also provided a 0.75% carrying charge related to those costs, subject to true-up based on actual financing costs.

In September 2022, PSO received proceeds of $687 million from the ODFA which issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event, which were previously recorded as Regulatory Assets on PSO's balance sheet. The securitization bonds are the obligation of the ODFA and there is no recourse against PSO in the event of a bond default, and therefore are not recorded as Long-term Debt on PSO's balance sheet. PSO will serve as the servicing agent of the bonds and is responsible for the routine billing and collection of the securitization charges and remitting those collections back to the ODFA. The securitization charges billed to and collected from customers are not included as revenue on PSO's statement of income. The collections from customers will occur over 20 years.

In March 2021, the APSC issued an order authorizing recovery of the Arkansas jurisdictional share of the retail customer fuel costs over five years, with the appropriate carrying charge to be determined at a later date. Subsequently, SWEPCo began recovery of these fuel costs. In April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05%. In June 2022, the APSC ordered SWEPCo to recover the Arkansas jurisdictional share of the fuel costs over six years with a carrying charge equal to its weighted average cost of capital, subject to a prudency review and true-up.

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 of 3.25%. SWEPCo will work with the LPSC to finalize the actual recovery period and determine the appropriate carrying charge in future proceedings.

In August 2021, SWEPCo filed an application with the PUCT to implement a net interim fuel surcharge for the Texas jurisdictional share of these retail fuel costs. The application requested a five-year recovery with a carrying charge of 7.18%. In March 2022, the PUCT ordered SWEPCo to recover the Texas jurisdictional share of the fuel costs over five years with a carrying charge of 1.65% and ordered SWEPCo to file a fuel reconciliation addressing fuel costs from January 1, 2020 through December 31, 2021.

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.

- AEP transitioned to stand-alone treatment of NOLC in its PJM and SPP transmission formula rates beginning with 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 2021 and 2022 annual revenue requirements by $78 million and $60 million, respectively. Through year-end 2022, the Registrants' financial statements reflect a provision for refund for certain NOLC revenues billed by PJM and SPP. Also, a certain portion of the impact of inclusion of the NOLC in the 2021 annual formula rate true-up not yet billed by PJM and SPP is not reflected in the Registrants' revenues and expenses as the Registrants have not met the requirements of alternative revenue recognition in accordance with the accounting guidance for "Regulated Operations".

  AEP is also transitioning to stand-alone treatment of NOLC in retail jurisdiction base rate case filings. As a result of retail jurisdiction base rate cases in Arkansas, Indiana, Oklahoma and Texas, inclusion of NOLCs in rates in those jurisdictions is contingent upon a supportive private letter ruling from the IRS. If the Registrant Subsidiaries are successful in transitioning to stand-alone treatment of NOLC, it could have a material, favorable impact on future net income.

- *SPP Capacity Planning Reserve Margin* - In July 2022, SPP approved a plan to increase its capacity planning reserve margin from 12% to 15% starting in the summer of 2023. Compliance filings were made with SPP in February 2023 and any deficiencies are required to be remedied by May 2023. SPP's annual non-compliance charge as a result of not meeting capacity requirements could range from approximately $86 thousand per MW to approximately $171 thousand per MW under the current SPP tariff. Non-compliance could also result in a failure to meet NERC criteria. As of December 31, 2022, the increase in the capacity planning reserve margin for PSO and SWEPCo to comply with this new SPP requirement was approximately 265 MWs.

Management has been taking actions and expects to comply with SPP's 2023 capacity planning reserve margin requirement. If PSO or SWEPCo incur charges or are unable to recover, or experience delays in recovering, the costs of complying with SPP's rule, it could reduce future net income and cash flows and impact financial condition.

Utility Rates and Rate Proceedings

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

The following tables show the Registrants' completed and pending base rate case proceedings in 2022. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (in millions)		Approved ROE	New Rates Effective
SWEPCo	Texas	$ 39.4		9.25%	March 2021
I&M	Indiana	61.4	(a)	9.7%	February 2022
SWEPCo	Arkansas	48.7		9.5%	July 2022
KGPCo	Tennessee	5.8		9.5%	August 2022
SWEPCo	Louisiana	21.0		9.5%	February 2023

(a) See "2021 Indiana Base Rate Case" section of Note 4 - Rate Matters in the 2021 Annual Report for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase (in millions)	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
PSO	Oklahoma	November 2022	$ 173.0	10.4%	(a)

(a) Intervenor testimony is expected to be filed in the first quarter of 2023.

Deferred Fuel Costs

Increased fuel and purchased power prices in excess of amounts included in fuel-related revenues has led to an increase in the under collection of fuel costs from customers in most jurisdictions. The table below illustrates the increase (decrease) in the deferred fuel regulatory assets by company and jurisdiction, excluding the impacts of the February 2021 severe winter weather event. See the "February 2021 Severe Winter Weather Impacts in SPP" sections in Note 4 for additional information.

Company	Jurisdiction	Traditional FAC Recovery Reset	As of December 31, 2022	As of December 31, 2021	Increase/ (Decrease)
APCo	Virginia (a)	Annually	$ 407.9	$ 128.6	$ 279.3
APCo	West Virginia	Annually	288.5	72.7	215.8
I&M	Indiana	Bi-Annually	38.1	—	38.1
I&M	Michigan	Annually	9.0	6.4	2.6
PSO	Oklahoma (b)	Annually	431.5	194.6	236.9
SWEPCo	Arkansas	Annually	65.8	23.1	42.7
SWEPCo	Louisiana	Monthly	—	11.1	(11.1)
SWEPCo	Texas	Tri-Annually	191.4	47.0	144.4
KPCo	Kentucky	Monthly	23.2	8.2	15.0
WPCo	West Virginia	Annually	231.1	101.6	129.5
		Total (c)	$ 1,686.5	$ 593.3	$ 1,093.2

(a) Includes $223 million of noncurrent deferred fuel classified as a Regulatory Asset on APCo's balance sheets as of December 31, 2022.
(b) Includes $253 million of noncurrent deferred fuel classified as a Regulatory Asset on PSO's balance sheets as of December 31, 2022.
(c) Includes $23 million and $8 million as of December 31, 2022 and December 31, 2021, respectively, of deferred fuel classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

The AEP utility subsidiaries are working with various state commissions on the timing of recovering deferred fuel balances and have made the following recent filings:

In April 2022, APCo and WPCo submitted their 2022 annual ENEC filing with the WVPSC requesting a $297 million annual increase in ENEC revenues, effective September 1, 2022. In February 2023, the WVPSC issued an order stating that the commission will not grant additional rate increases for fuel costs until the WVPSC staff completes its prudency review. See "2021 and 2022 ENEC Filings" section of Note 4 for additional information.

In August 2022, PSO requested an interim update to its annual Fuel Cost Adjustment (FCA) rates in accordance with the terms of the established tariff which allows PSO or the OCC staff to request an interim FCA adjustment in the event that the annual FCA over/under-recovered balance is $50 million or more on a cumulative basis. In September 2022, the Director of the Public Utility Division of the OCC approved a FCA rate designed to collect a $402 million deferred fuel balance over a 27-month period, effective with the first billing cycle of October 2022. PSO's fuel and purchased power expenses are subject to an annual prudency review by the OCC.

In September 2022, APCo submitted a request to the Virginia SCC to increase its annual fuel factor by approximately $279 million. APCo implemented interim FAC rates effective November 2022 subject to Virginia SCC review. To help mitigate the impact of rising fuel costs on customer bills, APCo proposed to recover its deferred fuel balance as of October 31, 2022 over two years. An order from the Virginia SCC is expected in the first quarter of 2023.

In September 2022, SWEPCo filed a request with the APSC for an interim increase to its current Energy Cost Rate (ECR) to recover $44 million of additional fuel costs incurred from April 2022 through August 2022, subsequent to the last annual ECR rate change. The interim rate was effective with the first billing cycle of October 2022 and will be in effect for six months until the ECR is reset in April 2023.

In October 2022, SWEPCo filed a request with the PUCT for an interim fuel surcharge to recover $83 million of additional fuel costs incurred through August 2022. An interim rate is effective February 2023, subject to final approval by the PUCT.

Dolet Hills Power Station and Related Fuel Operations

In 2020, management of SWEPCo and CLECO determined DHLC would not develop additional Oxbow Lignite Company (Oxbow) mining areas for future lignite extraction and ceased extraction of lignite at the mine in May 2020. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining. 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, 2022, SWEPCo's share of the net investment in the Dolet Hills Power Station is $112 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, 2022, SWEPCo had a net under-recovered fuel balance of $257 million, inclusive of costs related to 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 $32 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 $72 million, including denial of recovery of the $32 million deferral, with refunds to customers over five years. In September 2022, SWEPCo filed rebuttal testimony addressing the LPSC staff recommendations.

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 August 2022, SWEPCo filed a fuel reconciliation with the PUCT covering the fuel period of January 1, 2020 through December 31, 2021. Intervenor testimony is due in the first quarter of 2023 and a decision from the PUCT is expected in the third quarter of 2023.

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

Pirkey Plant and Related Fuel Operations

In 2020, management announced plans to retire the Pirkey Plant in 2023. The Pirkey Plant non-fuel costs are recoverable by SWEPCo through base rates and rate riders. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized recovery of SWEPCo's Louisiana share of the Pirkey Plant through a separate rider. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of December 31, 2022, SWEPCo's share of the net investment in the Pirkey Plant is $215 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $43 million as of December 31, 2022. As of December 31, 2022, SWEPCo had a net under-recovered fuel balance of $257 million, inclusive of costs related to Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Upon cessation of lignite deliveries by Sabine to the Pirkey Plant, additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Renewable Generation

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

Contracted Renewable Generation Facilities

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

In February 2022, AEP management announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio within the Generation & Marketing segment. Subsequently, AEP's investment in Flat Ridge 2 Wind LLC was removed from the competitive contracted renewables sale portfolio. In June 2022, as a result of 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 and recorded a pretax other than temporary impairment charge of $186 million in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's statements of income. In the third quarter of 2022, in accordance with the accounting guidance for "Investments - Equity Method and Joint Ventures", AEP recorded an additional $2 million pretax other than temporary impairment charge in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's statements of income. AEP has recorded a $188 million other than temporary impairment in its investment in Flat Ridge 2 for the year ended December 31, 2022 in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's statements 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 nonaffiliate. 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.

As of December 31, 2022, the competitive contracted renewable portfolio assets totaled 1.4 gigawatts of generation resources representing consolidated solar and wind assets, with a net book value of $1.2 billion, and a 50% interest in four joint venture wind farms, totaling $247 million, accounted for as equity method investments.

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 competitive contracted renewables portfolio and AEP signed an agreement to sell the competitive contracted renewables portfolio to a nonaffiliated party for $1.5 billion including the assumption of project debt. As part of the sale agreement, AEP provided the acquirer an indemnification related to certain losses, not to exceed $70 million, which could result from one of the joint venture wind farm's inability to meet certain minimum performance requirements.

The sale is subject to FERC approval, clearance from the Committee on Foreign Investment in the United States and approval under applicable competition laws. AEP expects to close on the sale in the second quarter of 2023 and receive cash proceeds, net of taxes, transaction fees and other customary closing adjustments, of approximately $1.2 billion.

Management concluded the consolidated assets within the competitive contracted renewables portfolio met the accounting requirements to be presented as Held for Sale in the first quarter of 2023 based on the receipt of final bids, Board of Director approval to consummate a sale transaction and the signing of the sale agreement. AEP anticipates recording an estimated pretax loss ranging from $175 million to $225 million ($100 million to $150 million after-tax), in the first quarter of 2023 as a result of reaching Held for Sale status. Management concluded the impact of any other than temporary decline in the fair value of the four joint venture wind farms was not material to AEP's December 31, 2022 financial statements. Any changes to the book value or carrying value of these assets, or the anticipated sale price, could further reduce future net income and impact financial condition.

Regulated Renewable Generation Facilities

North Central Wind Facilities

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs. PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. 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 beginning at commercial operation and until such time as amounts are reflected in base rates. The Arkansas portion of the NCWF revenue requirement was approved for recovery through base rates in the 2021 Arkansas base rate case. The table below provides a summary of the facilities as of December 31, 2022:

Project	In-Service Date	Net Book Value	Federal PTC Qualification % (a)	Generating Capacity
		(in millions)		(in MWs)
Sundance	April 2021	$ 282.3	100 %	199
Maverick	September 2021	398.3	80 %	287
Traverse	March 2022	1,255.0	100 % (b)	998

(a) PTC benefits are available for a ten year period following the in-service date.
(b) The PTC for Traverse was increased to 100% in the third quarter of 2022 as a result of the IRA legislation.

See "North Central Wind Energy Facilities" section of Note 7 for additional information.

Recent Renewable Generation Filings

In December 2021 and January 2022, APCo filed petitions with the Virginia SCC and WVPSC, respectively, for prudency and cost recovery of several renewable projects. In July 2022, the Virginia SCC approved APCo's December 2021 petition for prudency and cost recovery. In January 2023, the WVPSC issued an order approving the remaining projects included in the petition. The table below provides a list of all remaining projects from the APCo petitions.

Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
			(in MWs)
Solar	Second Quarter 2023	Owned	5
Solar	Fourth Quarter 2025	PPA	20
Solar	In Operation	PPA	15
Wind	Third Quarter 2025	Owned	204
Total Renewable Projects			**244**

In May 2022, SWEPCo submitted filings before the APSC, LPSC and PUCT requesting approval to acquire three renewable energy projects totaling 999 MWs. In October 2022, SWEPCo also submitted the necessary filings with the FERC. The projects are comprised of two wind facilities, totaling 799 MWs, and one solar facility, totaling 200 MWs. One of the wind facilities, totaling approximately 201 MWs, is expected to reach commercial operation in December 2024 with the remaining facilities expected to reach commercial operation in December 2025. In January 2023, a hearing was held at the PUCT. Additionally in January 2023, SWEPCo filed an unopposed joint settlement agreement with the APSC that supported approval of the projects. An order from the APSC is expected in the second quarter of 2023. In December, 2022, an intervenor filed suit seeking injunctive relief to effectively halt SWEPCo's regulatory proceedings, among other relief; however, the magistrate judge for the United States District Court for the Eastern District of Texas has recommended denial of intervenor's request for injunctive relief.

In November 2022, PSO submitted filings with the OCC requesting approval of its fuel-free power plan to purchase three new wind farms, totaling approximately 553 MWs, and three new solar facilities, totaling approximately 443 MWs. These projects are expected to reach commercial operation in 2025. This proposed plan will help meet projected power needs while protecting customers from volatility in energy costs driven by high natural gas and power prices. In addition, PSO has recently executed an agreement to purchase the 154 MW Rock Falls Wind Facility, and has requested cost recovery in the 2022 Oklahoma Base Rate Case. In February 2023, the FERC approved PSO's acquisition of the Rock Falls Wind Facility under Section 203 of the Federal Power Act. See "2022 Oklahoma Base Rate Case" section of Note 4 for additional information.

Significant Renewable Generation Requests for Proposal (RFP)

As part of AEP's transition to diversify the company's generation resources and build its renewable generation portfolio, the Registrants file RFPs in an effort to identify potential wind and solar projects. The table below includes RFPs recently issued for owned generation. These projects would be subject to regulatory approval.

Company	Issuance Date	Generation Type	Generating Capacity (in MWs)
APCo	January 2022	Wind	1,000
APCo	January 2022	Solar (a)	100
I&M	March 2022	Wind (a)(b)	800
I&M	March 2022	Solar (a)(b)	500
SWEPCo	September 2022	Wind (a)	1,900
SWEPCo	September 2022	Solar (a)	500
Total Significant RFPs			**4,800**

(a) Includes an option for battery storage.
(b) Includes solicitation of bids for both owned projects and PPAs.

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. In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. AEP has received clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR) and the Committee on Foreign Investment in the United States during 2022. Clearance under the HSR expired in January 2023. AEP and Liberty refiled a joint application seeking HSR clearance in February 2023. The sale is also contingent upon FERC approval under Section 203 of the Federal Power Act. The parties to the SPA have certain termination rights if the closing of the sale does not occur by April 26, 2023.

Transfer of Ownership

FERC Proceedings

In December 2021, Liberty, KPCo and KTCo (the applicants) requested FERC approval of the sale under Section 203 of the Federal Power Act. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission rates of applicants. In April 2022, the FERC issued a deficiency letter stating that the Section 203 application is deficient and that additional information is required to process it. In May 2022, Liberty, KPCo and KTCo supplemented the application. 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 January 2023, AEP, AEPTCo, and Liberty entered into an amendment to the SPA that specified the applicants will submit a new filing for approval under Section 203 of the Federal Power Act. The new filing was submitted to the FERC on February 14, 2023. The applicants requested expedited treatment of the new filing, including an accelerated comment period. In response, the FERC granted a shortened 45 day comment period. The applicants believe the new Section 203 application addresses the concerns raised in the FERC's December 2022 order. The application contains several additional commitments by Liberty to mitigate potential adverse impacts on FERC jurisdictional rates over the next five years, including: a) maintaining the current return on equity; b) maintaining the current cost cap on equity; c) financing future investments at the current credit rating; and d) capping certain operating and administrative costs. The sale remains subject to FERC approval. The statute requires an order from the FERC within 180 days of the February 14, 2023 filing date in accordance with Section 203 of the Federal Power Act.

KPSC Proceedings

In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to conditions contingent upon the closing of the sale, including establishment of regulatory liabilities to subsidize retail customer transmission and distribution expenses, a fuel adjustment clause bill credit, and a three-year Big Sandy decommissioning rider rate holiday during which KPCo's carrying charge is reduced by 50%.

Mitchell Plant Operations and Maintenance Agreement and Ownership Agreement

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant. As of December 31, 2022 and 2021, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $577 million and $586 million, respectively. The SPA includes a condition precedent to closing requiring the issuance of regulatory orders approving new Mitchell Plant agreements.

The KPSC and WVPSC issued orders proposing materially different modifications to the Mitchell Plant agreements filed by AEP such that the new agreements could not be executed by the parties. In lieu of new agreements, in July 2022, KPCo and WPCo confirmed with the KPSC and WVPSC, respectively, that they will continue operating under the existing Mitchell Agreement, utilizing the Mitchell Agreement Operating Committee's authority under that agreement to issue appropriate resolutions so the parties can operate in accordance with each state commission's directives related to CCR and ELG investment. In September 2022, pursuant to resolutions under the existing Mitchell Plant agreement, WPCo replaced KPCo as the Operator of Mitchell Plant.

Summary

As a result of the conditions imposed by the KPSC's May 2022 order, in the second quarter of 2022, AEP recorded a $69 million loss on the expected sale of the Kentucky Operations in accordance with accounting guidance for Fair Value Measurement.

In September 2022, AEP, AEPTCo and Liberty entered into an amendment to the SPA which reduced the purchase price to approximately $2.646 billion and Liberty agreed to waive, upon FERC approval of the sale, the SPA condition precedent to closing requiring the issuance of regulatory orders approving new proposed Mitchell Plant agreements. Further, as a result of the reduced purchase price from the September Amendment and the change to the anticipated timing of the completion of the transaction, AEP recorded an additional $194 million pretax loss ($149 million net of tax) on the expected sale of the Kentucky Operations in the third quarter of 2022 in accordance with the accounting guidance for Fair Value Measurement.

As a result of the December 2022 FERC order and resulting delay in the anticipated timing of the closing of the transaction, AEP recorded an additional $100 million pretax loss ($79 million net of tax) on the expected sale of the Kentucky Operations in December 2022 in accordance with the accounting guidance for Fair Value Measurement. In total, AEP recorded a $363 million pretax loss of ($297 million net of tax) on the expected sale of the Kentucky Operations for the twelve months ended December 31, 2022.

Management believes it is probable that FERC authorization under Section 203 of the Federal Power Act will be received and closing will occur after receipt of the order. Therefore, the assets and liabilities of KPCo and KTCo were classified as Held for Sale in the December 31, 2022 balance sheets of AEP and AEPTCo. Upon closing, Liberty will acquire the assets and assume the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction. AEP expects cash proceeds, net of taxes and transaction fees, from the sale of approximately $1.2 billion. AEP plans to use the proceeds from the sale to fund its continued investment in regulated businesses, including transmission and regulated renewables projects. If additional reductions in the fair value of the Kentucky Operations occur, it would reduce future net income and cash flows.

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 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. As of December 31, 2022, 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.

Winter Storm Elliott

In December 2022, severe winter weather and extreme cold temperatures resulted in an unusually high demand for electricity and the declaration of an Energy Emergency Alert (EEA) in the PJM region. The EEA was in effect from December 23, 2022 through December 25, 2022. During this time, all electric generating units located within the PJM region were directed to operate up to their maximum generation output levels. The issuance of the EEA also triggered PJM Performance Assessment Intervals (PAI) for each committed generation capacity resource. During a PAI event, PJM evaluates the performance of each committed capacity resource against PJM performance standards. Generating units that underperform during a PAI event are subject to non-performance charges while generating units that perform above expectations are awarded performance bonuses. PJM awards and allocates the bonus performance payments from the pool of non-performance charges collected during the PAI event. PJM provided preliminary performance standards for each generating resource in January 2023 and additional preliminary generating unit performance data was released by PJM in February 2023. PJM currently expects to invoice non-performance charges and bonus payments in the month-end bill for March 2023 issued in early April 2023. As of December 31, 2022, based on preliminary PJM performance standards and internal generation estimates, OPCo and APCo recorded $7 million and $2 million, respectively, of non-performance charges from the December PAI event in Electricity, Transmission and Distribution revenues and Purchased Electricity, Fuel and Other Consumables Used for Electric Generation, respectively, on the statements of income. The Registrants did not record estimated bonus performance payments as of December 31, 2022 as those amounts were not reasonably estimable.

LITIGATION

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

Rockport Plant Litigation

In 2013, the Wilmington Trust Company filed suit in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs sought a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. See "Obligations under the New Source Review Litigation Consent Decree" section below for additional information.

After the litigation proceeded at the district court and appellate court, in April 2021, I&M and AEGCo reached an agreement to acquire 100% of the interests in Rockport Plant, Unit 2 for $116 million from certain financial institutions that own the unit through trusts established by Wilmington Trust, the nonaffiliated owner trustee of the ownership interests in the unit. The transaction closed at the expiration of the Rockport Plant, Unit 2 lease in December 2022 and also resulted in a final settlement of, and release of claims in, the lease litigation.

Subsequent to the end of the Rockport Plant, Unit 2 lease in December 2022, AEGCo's 50% ownership share of Rockport Plant, Unit 2 is being billed to I&M under a FERC-approved UPA. I&M's purchased power from AEGCo and I&M's 50% ownership share of Rockport Plant, Unit 2 electricity generated represent a merchant resource for I&M until Rockport Plant, Unit 2 is retired in 2028. A 2021 IURC order approved a settlement agreement addressing the future use of Rockport Plant, Unit 2 as a short-term capacity resource through the June 2023 - May 2024 PJM planning year. The MPSC issued an order in February 2023 approving the settlement agreement on I&M's 2022 Integrated Resource Plan (IRP) filing, which included certain cost recovery for the remaining net book value of leasehold improvements made during the term of the Rockport Plant, Unit 2 lease and future use of Rockport Plant, Unit 2 as a capacity resource. If I&M cannot recover its future investment and expenses related to the merchant share of Rockport Plant Unit 2, it could reduce future net income and cash flows and impact financial condition.

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

Four participants in The American Electric Power System Retirement Plan (the Plan) filed a class action complaint in December 2021 in the U.S. District Court for the Southern District of Ohio against AEPSC and the Plan. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The plaintiffs assert a number of claims on behalf of themselves and the purported class, including that: (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career, (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act and (c) AEP failed to provide required notice regarding the changes to the Plan. Among other relief, the Complaint seeks reformation of the Plan to provide additional benefits and the recovery of plan benefits for former employees under such reformed plan. The plaintiffs previously had submitted claims for additional plan benefits to AEP, which were denied. On February 15, 2022, AEPSC and the Plan filed a motion to dismiss the complaint for failure to state a claim. On August 16, 2022, the district court granted the motion to dismiss the complaint without prejudice. The plaintiffs filed a motion for leave to file an amended complaint, which the Court denied on December 1, 2022. The plaintiffs did not file an appeal by the deadline of January 3, 2023.

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. The amended complaint alleged misrepresentations or omissions by AEP regarding: (a) its alleged participation in or connection to public corruption with respect to the passage of HB 6 and (b) its regulatory, legislative, political contribution, 501(c)(4) organization contribution and lobbying activities in Ohio. The complaint sought monetary damages, among other forms of relief. 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 on April 29, 2022. On September 13, 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiffs subsequently filed a notice of appeal with the New York appellate court. On January 20, 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York on January 24, 2023. AEP filed a brief in opposition to intervention on February 3, 2023. 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 on May 3, 2022 and briefing on the motion to dismiss has been completed. Discovery remains stayed pending the district court's ruling on the motion to dismiss. The plaintiff in the Ohio state court case advised that they no longer agreed to stay the proceedings, therefore, AEP filed a motion to continue the stays of proceedings on May 20, 2022 and the plaintiff filed an amended complaint on June 2, 2022. On June 15, 2022, the Ohio state court entered an order continuing the stays of that case until the resolution of the consolidated derivative actions pending in Ohio federal district court. 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 is directed to the Board of Directors of AEP and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by directors and officers, and that, following such investigation, AEP commence a civil action for breaches of fiduciary duty and related claims and take appropriate disciplinary action against those individuals who allegedly harmed the company. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect.

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. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this investigation will have a material impact on financial condition, results of operations or cash flows.

Claims for Indemnification Related to Damages Resulting from the Federal EPA's Denial of Alternative Closure Deadline for Gavin Plant and Associated Findings of Compliance

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 determinations related to the CCR Rule (see "Coal Combustion Residual (CCR) Rule" section below for additional information), including a determination 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 the Gavin Denial, as well as any future enforcement or litigation resulting from the Federal EPA's determinations of noncompliance with various aspects of the CCR Rule as part of the Gavin Denial. 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.

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 System generating units. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2022, the AEP System owned generating capacity of approximately 25,000 MWs, of which approximately 11,300 MWs were coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on fossil generation. Based upon management estimates, AEP's future investment to meet these existing and proposed requirements ranges from approximately $125 million to $200 million through 2026.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or revising certain existing requirements. The cost estimates will also change based on: (a) potential state rules that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) actual performance of the pollution control technologies installed, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity, (g) compliance with the Federal EPA's revised coal combustion residual rules and (h) other factors. In addition, management continues to evaluate the economic feasibility of environmental investments on regulated and competitive plants.

Obligations under the New Source Review Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_X emissions from the AEP System and various mitigation projects. The consent decree has been modified seven times, for various reasons, most recently in 2022. All of the environmental control equipment required by the consent decree has been installed.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to NAAQS and the development of SIPs to achieve 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 January 2023, the Federal EPA announced its proposed decision to strengthen the primary (health-based) annual PM2.5 standard. The Biden administration has previously indicated that it is likely to revisit the NAAQS for ozone, which were left unchanged by the prior administration following its review. Management cannot currently predict if any changes to either standard are likely to be finalized or what such changes may be, but will continue to monitor this issue and any future rulemakings.

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR) in 2005, which could require power plants and other facilities to install best available retrofit technology to address regional haze in federal parks and other protected areas. CAVR is implemented by the states, through SIPs, or by the Federal EPA, through FIPs. In 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postponed the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

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

In Texas, the Federal EPA disapproved portions of the Texas regional haze SIP and finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_X regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations. Legal challenges to these various rulemakings are pending in both the U.S. Court of Appeals for the Fifth Circuit and the U.S. Court of Appeals for the District of Columbia 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 designed to address interstate transport of emissions that contribute significantly to non-attainment and maintenance of the 1997 ozone and 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.

In January 2021, the Federal EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NO_X budgets in 2021-2024. Several utilities and other entities potentially subject to the Federal EPA’s NO_X regulations have challenged that final rule in the U.S. Court of Appeals for the District of Columbia Circuit and oral arguments were held in September 2022. Management cannot predict the outcome of that litigation, but 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 EPA Administrator finalized the denial of 2015 Ozone NAAQS SIPs for 19 states. A FIP that further revises the ozone season NO_X budgets under the existing CSAPR program in those states is expected to be finalized in the spring of 2023 and will likely take effect for the 2023 ozone season. Management is evaluating the impacts of the rule changes.

Climate Change, CO_2 Regulation and Energy Policy

In 2019, the Affordable Clean Energy (ACE) rule established a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. However, in January 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it to the Federal EPA. In October 2021, the United States Supreme Court granted certiorari and combined four separate petitions seeking review of the District of Columbia Circuit Court decisions. Oral arguments were held in February 2022 and on June 30, 2022, the United States Supreme Court reversed the District of Columbia Circuit Court’s decision and remanded for further proceedings. The Federal EPA must take some action before anything is required of the utilities as a result of this decision. At a minimum, if the Federal EPA intends to implement the ACE rule, it must conduct additional rulemaking to update its applicable deadlines, which have all passed. Alternatively, the Federal EPA may abandon the ACE rule and proceed to regulate greenhouse gases through a new rule, the scope of which is unknown. The Federal EPA has announced it expects to propose a new rule in 2023. Management is unable to predict how the Federal EPA will respond to the Court’s remand.

In 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. That rule has not been finalized. The Federal EPA has indicated that it intends to conduct a comprehensive review of the existing standards and, if appropriate, amend the emission standards for new fossil fuel-fired generating units. A proposed rule is expected in 2023. Management continues to actively monitor these rulemaking activities.

While no federal regulatory requirements to reduce CO_2 emissions are in place, AEP has taken action to reduce and offset CO_2 emissions from its generating fleet. AEP expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. In April 2020, Virginia enacted clean energy legislation to allow the state to participate in the Regional Greenhouse Gas Initiative (RGGI), require the retirement of all fossil-fueled generation by 2045 and require 100% renewable energy to be provided to Virginia customers by 2050. Management is taking steps to comply with these requirements, including increasing wind and solar installations, purchasing renewable power and broadening AEP System's portfolio of energy efficiency programs. In early 2022, Virginia's governor issued an executive order directing his administration to end Virginia's participation in RGGI. In December 2022, the Virginia Air Pollution Control Board voted in support of the proposed regulations to withdraw Virginia from RGGI. These regulations have not been finalized. Management will continue to monitor these rulemaking activities.

In October 2022, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, grid reliability and resiliency, regulations and the company's current business strategy. AEP adjusted its near-term carbon dioxide 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. AEP's total Scope 1 GHG emissions in 2022 were approximately 52.5 million metric tons CO_2e, approximately a 65% 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. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

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

Coal Combustion Residual (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 will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR. Additionally, each request must undergo formal review, including public comments, and be approved by the Federal EPA. AEP filed applications for additional time to develop alternative disposal capacity at the following plants:

Company	Plant Name	Generating Capacity	Net Book Value (a)		Projected Retirement Date
		(in MWs)	(in millions)		
AEGCo	Rockport Plant, Unit 1	655	$ 226.0		2028
APCo	Amos	2,930	2,140.2		2040
APCo	Mountaineer	1,320	980.8		2040
I&M	Rockport Plant, Unit 1	655	449.2	(b)	2028
KPCo	Mitchell Plant	780	576.7		2040
SWEPCo	Flint Creek Plant	258	265.4		2038
WPCo	Mitchell Plant	780	638.3		2040

(a) Net book value as of December 31, 2022, before cost of removal including CWIP and inventory.
(b) Amount includes a $147 million regulatory asset related to the retired Tanners Creek Plant. The IURC and MPSC authorized recovery of the Tanners Creek Plant regulatory asset over the useful life of Rockport Plant, Unit 1 in 2015 and 2014, respectively.

In 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 Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements. The January Actions of the Federal EPA 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.

In July 2022, the Federal EPA proposed conditional approval of the pending extension request for the 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. The Federal EPA has not yet proposed any action on the other pending extension requests submitted by AEP. However, statements made by the Federal EPA in the context of the proposed and final decisions on extension requests issued to date indicate that there is a risk that the Federal EPA may conclude that AEP is not eligible for an extension of time to cease use of those CCR impoundments for which extension requests are pending and/or that one or more of AEP's facilities is not in compliance with the CCR Rule. If that occurs, AEP may incur material additional costs to change its plans for complying with the CCR Rule, including the potential to have to temporarily cease operation of one or more facilities until an acceptable compliance alternative can be implemented. Such temporary cessation of operation could materially impact the cost of serving customers of the affected utility. Further, actions by the Federal EPA could require AEP to remove coal ash from CCR units that have already been closed in accordance with state law programs or could require AEP to incur costs related to CCR units at various active and legacy facilities.

Closure and post-closure 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.

The second option to obtain an extension of the April 11, 2021 deadline to cease operation of unlined impoundments allows a generating facility to 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 would have 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. The table below summarizes the net book value of the Pirkey Plant and Welsh Plant, Units 1 and 3 as of December 31, 2022.

Company	Plant Name and Unit	Generating Capacity	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Projected Retirement Date
		(in MWs)	(in millions)		
SWEPCo	Pirkey Plant	580	$ 35.1	$ 179.5	2023 (b)
SWEPCo	Welsh Plant, Units 1 & 3	1,053	416.8	85.6	2028 (c)(d)

(a) Net book value as of December 31, 2022, including CWIP and excluding cost of removal and materials and supplies.
(b) In January 2023, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Pirkey Plant through a separate rider through 2032. See Note 4 - Rate Matters for additional information. The Pirkey Plant is currently being recovered through 2045 in the Arkansas and Texas jurisdictions.
(c) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(d) Unit 1 is currently being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is currently being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

To date, the Federal EPA has not taken any action on these pending extension requests. Under the second option above, AEP may need to recover remaining depreciation and estimated closure costs associated with these plants over a shorter period. If AEP cannot ultimately recover the costs of environmental compliance and/or the remaining depreciation and estimated closure costs associated with these plants in a timely manner, it would reduce future net income and cash flows and impact financial condition.

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, establishes additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units and extends the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. Management has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. 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. The Federal EPA has announced its intention to reconsider the 2020 rule and to further revise limits applicable to discharges of landfill and impoundment leachate. A proposed rule is expected in 2023. Management cannot predict whether the Federal EPA will actually finalize further revisions or what such revisions might be, but will continue to monitor this issue and will participate in further rulemaking activities as they arise.

In January 2023, the Federal EPA finalized a new rule revising the definition of "waters of the United States," which will become effective in March 2023. The new rule expands the scope of the definition, which means that permits may be necessary where none were previously required and issued permits may need to be reopened to impose additional obligations. Management is evaluating what impacts the revised rule will have on operations.

In October 2022, the United States Supreme Court heard an appeal related to the scope of "waters of the United States," specifically which wetlands can be regulated as waters of the United States. Management cannot predict the outcome of that litigation.

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.

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

The table below summarizes the net book value, as of December 31, 2022, 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	$ 136.3	$ 145.8	2026	(c)	$ 14.9
SWEPCo	Dolet Hills Power Station	—	54.8	2021	(d)	—
SWEPCo	Pirkey Plant	35.1	179.5	2023	(e)	11.7
SWEPCo	Welsh Plant, Units 1 and 3	416.8	85.6	2028 (f)	(g)	37.9
SWEPCo	Welsh Plant, Unit 2	—	35.2	2016	(h)	—

(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) In January 2023, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Dolet Hills Power Station through a separate rider through 2032. In May 2022, 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 December 2021, the PUCT authorized the recovery of SWEPCo's Texas jurisdictional share of the Dolet Hills Power Station through 2046 without providing a return on the investment which resulted in a disallowance of $12 million. See Note 4 - Rate Matters for additional information.
(e) In January 2023, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Pirkey Plant through a separate rider through 2032. See Note 4 - Rate Matters for additional information. The Pirkey Plant is currently being recovered through 2045 in the Arkansas and Texas jurisdictions.
(f) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(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.
(h) In January 2023, the LPSC approved a settlement agreement which provided recovery of Welsh Plant, Unit 2 over the blended useful life of Welsh Plant, Units 1 and 3.

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

RESULTS OF OPERATIONS

SEGMENTS

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

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

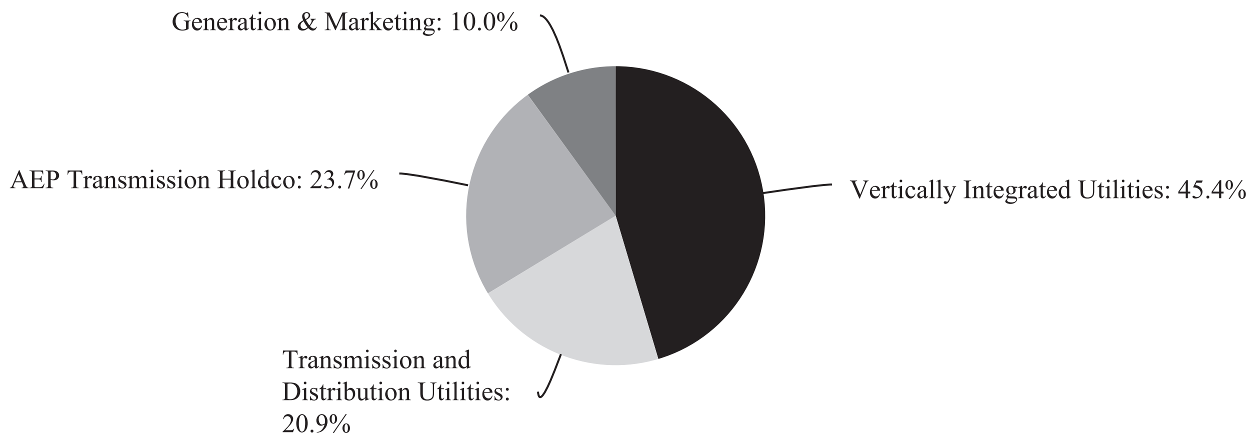
The following discussion of AEP's results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation, as well as Purchased Electricity for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

A detailed discussion of AEP's 2021 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 2021 Annual Report on Form 10-K filed with the SEC on February 24, 2022.

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

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Vertically Integrated Utilities	$ 1,292.0	$ 1,113.6	$ 1,061.6
Transmission and Distribution Utilities	595.7	543.4	496.4
AEP Transmission Holdco	673.5	677.8	504.8
Generation & Marketing	283.6	217.5	226.9
Corporate and Other	(537.6)	(64.2)	(89.6)
Earnings Attributable to AEP Common Shareholders	$ 2,307.2	$ 2,488.1	$ 2,200.1

2022 Earnings Attributable to AEP Common Shareholders by Segment



Note: 2022 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment.

AEP CONSOLIDATED

2022 Compared to 2021

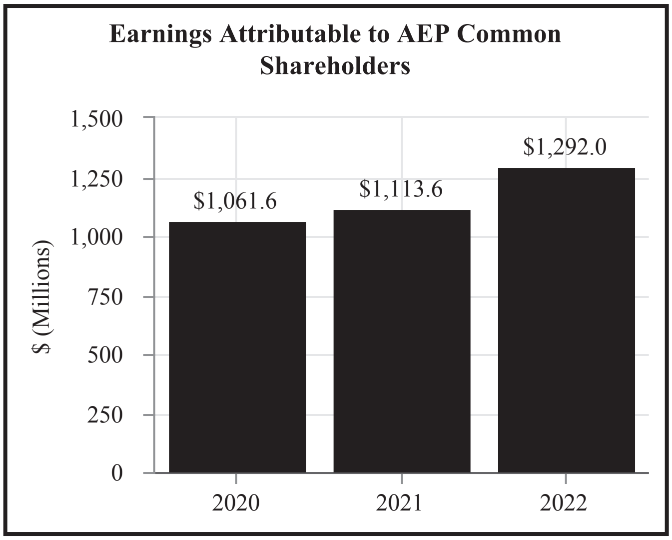
Earnings Attributable to AEP Common Shareholders decreased from $2.5 billion in 2021 to $2.3 billion in 2022.

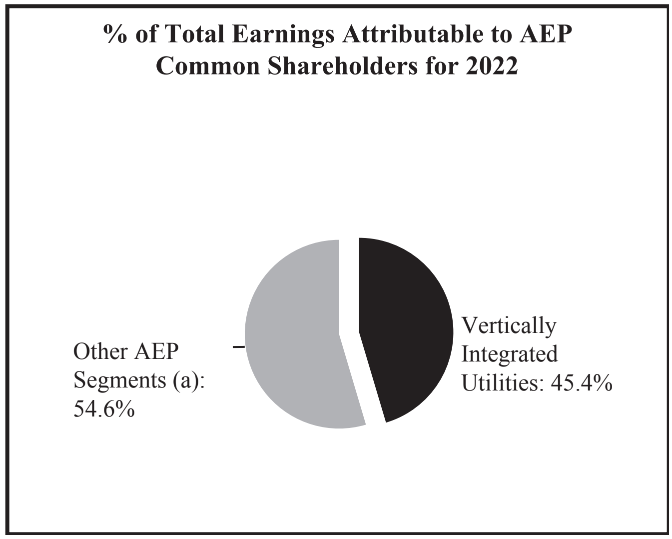
AEP's Earnings Attributable to AEP Common Shareholders in 2022 were positively impacted by favorable rate proceedings in various jurisdictions, higher earnings driven by continued transmission investment and increased sales volumes driven by favorable weather and load. In June 2022, AEP also recognized a gain on the sale of mineral rights which contributed to AEP's Earnings Attributable to AEP Common Shareholders.

The favorable items discussed above were more than offset by a loss on the expected sale of the Kentucky Operations, an impairment of AEP's equity investment in Flat Ridge 2, increases in interest expense due to higher interest rates and debt balances and a charitable contribution to the AEP Foundation.

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

VERTICALLY INTEGRATED UTILITIES





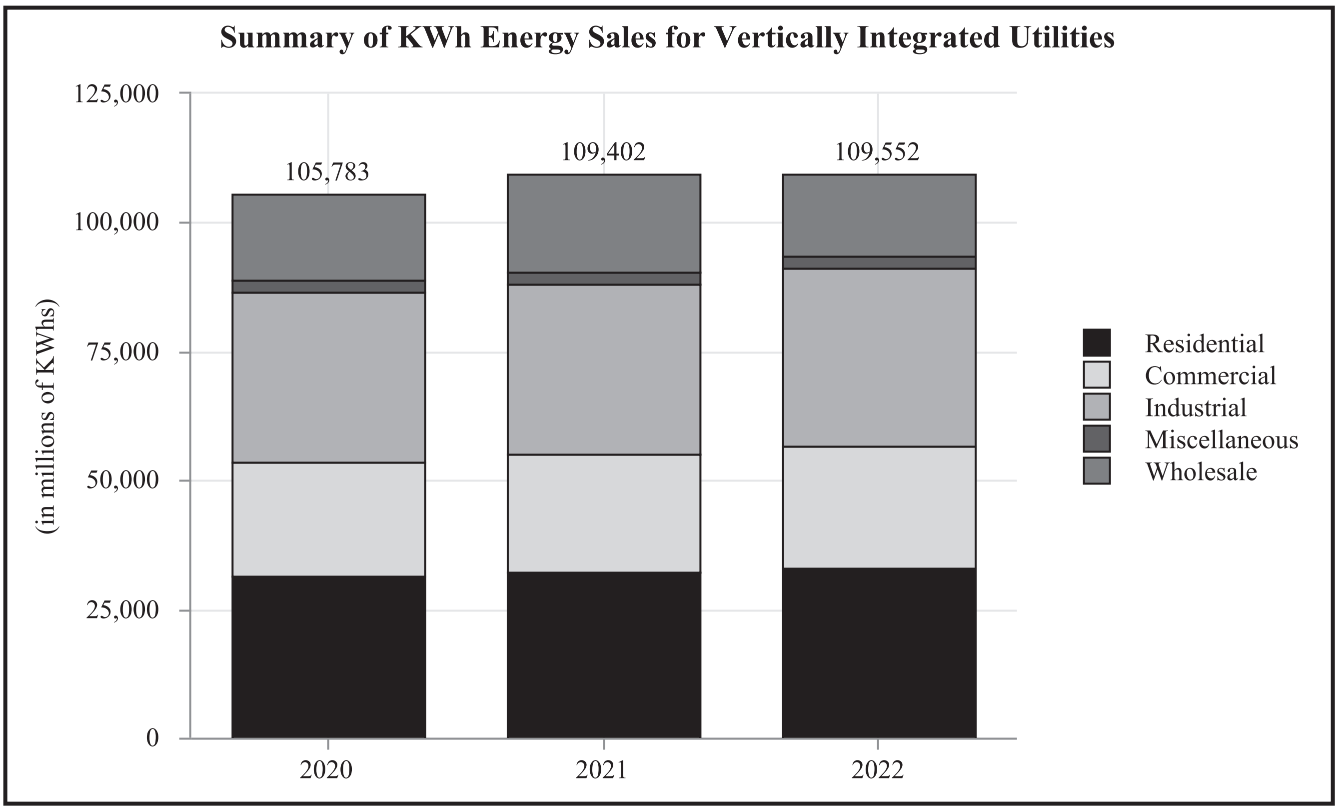
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Vertically Integrated Utilities	Years Ended December 31, 2022	2021	2020
		(in millions)	
Revenues	$ 11,477.5	$ 9,998.5	$ 8,879.4
Fuel and Purchased Electricity	4,007.9	3,144.2	2,544.9
Gross Margin	7,469.6	6,854.3	6,334.5
Other Operation and Maintenance	3,287.2	3,043.1	2,754.3
Asset Impairments and Other Related Charges	24.9	11.6	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	—
Depreciation and Amortization	2,007.2	1,747.6	1,600.5
Taxes Other Than Income Taxes	504.9	497.3	472.6
Operating Income	1,682.4	1,554.7	1,507.1
Other Income	30.2	13.5	2.4
Allowance for Equity Funds Used During Construction	29.5	40.2	42.2
Non-Service Cost Components of Net Periodic Benefit Cost	109.8	67.9	67.9
Interest Expense	(650.9)	(574.2)	(565.0)
Income Before Income Tax Benefit and Equity Earnings	1,201.0	1,102.1	1,054.6
Income Tax Benefit	(93.8)	(11.2)	(7.0)
Equity Earnings of Unconsolidated Subsidiary	1.4	3.4	2.9
Net Income	1,296.2	1,116.7	1,064.5
Net Income Attributable to Noncontrolling Interests	4.2	3.1	2.9
Earnings Attributable to AEP Common Shareholders	$ 1,292.0	$ 1,113.6	$ 1,061.6

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2022	2021	2020
	(in millions of KWhs)		
Retail:			
Residential	32,835	32,149	31,526
Commercial	23,770	22,833	22,225
Industrial	34,532	33,181	32,860
Miscellaneous	2,316	2,214	2,185
Total Retail	93,453	90,377	88,796
Wholesale (a)	16,099	19,025	16,987
Total KWhs	109,552	109,402	105,783

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

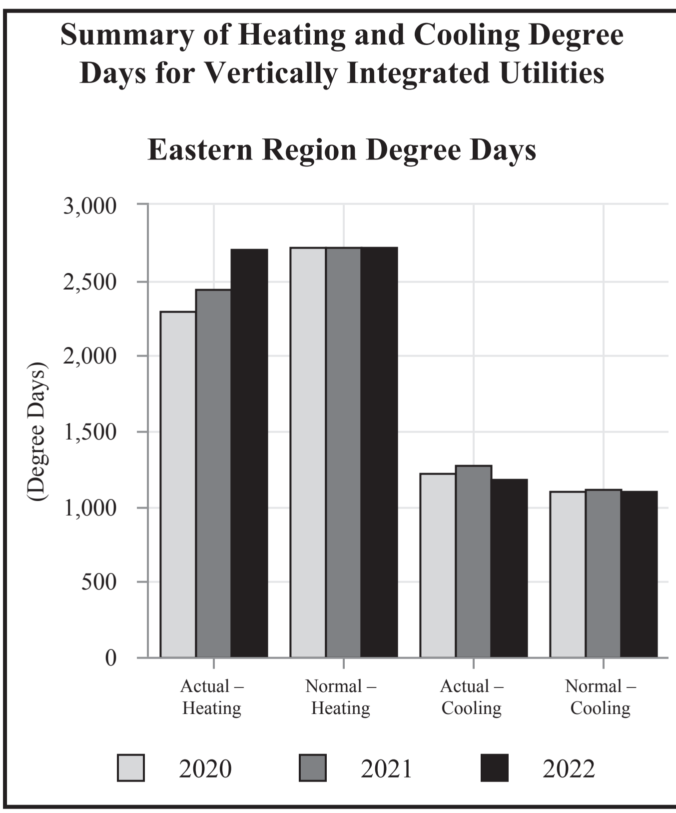


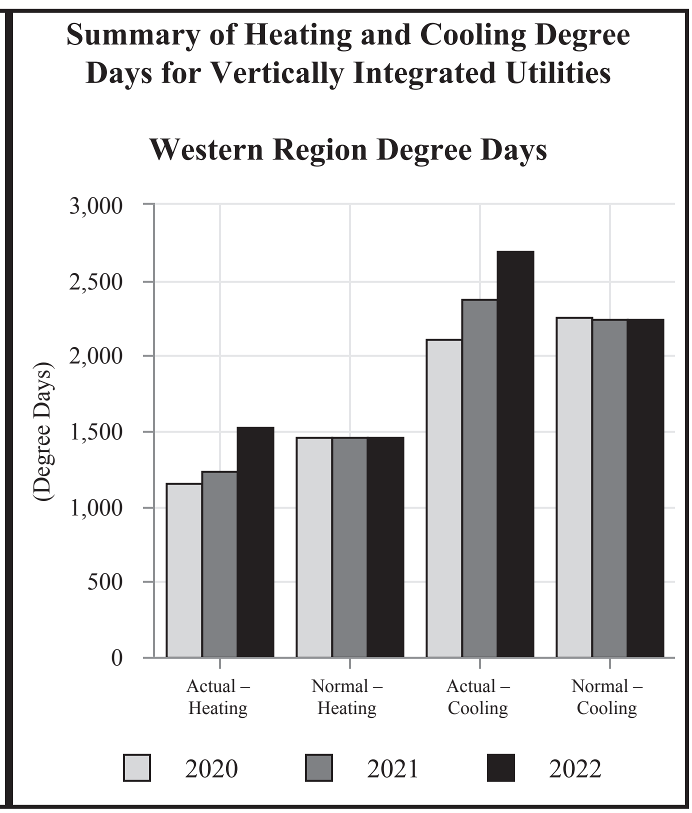
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31, 2022	2021	2020
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,709	2,438	2,295
Normal – Heating (b)	2,717	2,720	2,727
Actual – Cooling (c)	1,187	1,268	1,222
Normal – Cooling (b)	1,106	1,110	1,104
Western Region			
Actual – Heating (a)	1,523	1,241	1,160
Normal – Heating (b)	1,455	1,461	1,464
Actual – Cooling (c)	2,695	2,370	2,117
Normal – Cooling (b)	2,247	2,246	2,253

(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.





2022 Compared to 2021

Reconciliation of Year Ended December 31, 2021 to Year Ended December 31, 2022
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2021	$ 1,113.6
Changes in Gross Margin:	
Retail Margins	492.6
Margins from Off-system Sales	9.6
Transmission Revenues	81.9
Other Revenues	31.2
Total Change in Gross Margin	615.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(244.1)
Asset Impairments and Other Related Charges	(13.3)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	37.0
Depreciation and Amortization	(259.6)
Taxes Other Than Income Taxes	(7.6)
Other Income	16.7
Allowance for Equity Funds Used During Construction	(10.7)
Non-Service Cost Components of Net Periodic Pension Cost	41.9
Interest Expense	(76.7)
Total Change in Expenses and Other	(516.4)
Income Tax Benefit	82.6
Equity Earnings of Unconsolidated Subsidiary	(2.0)
Net Income Attributable to Noncontrolling Interests	(1.1)
Year Ended December 31, 2022	$ 1,292.0

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

- **Retail Margins** increased $493 million primarily due to the following:
  - A $127 million increase at APCo and WPCo due to an increase in rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - A $110 million increase at PSO due to a $61 million increase in base rate revenues and a $49 million increase in rider revenues. These increases were partially offset in other expense items below.
  - A $102 million increase at SWEPCo primarily due to base rate revenue increases in Texas and Arkansas and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - An $87 million increase in rider revenues at I&M partially offset by lower wholesale true-ups. This increase was partially offset in other expense items below.
  - A $69 million increase in weather-related usage primarily in the residential class.
  - A $30 million increase in weather-normalized retail margins primarily in the commercial class.
  - A $17 million increase at APCo due to a base rate increase in Virginia implemented in October 2022 following the Virginia Supreme Court remand. This increase was partially offset in Other Operation and Maintenance expense below.

These increases were partially offset by:
- A $73 million decrease at PSO and SWEPCo due to the NCWF PTC benefits provided to customers through fuel clause mechanisms. This decrease was partially offset in Income Tax Benefit below.
- A $6 million decrease in municipal and cooperative revenues at SWEPCo primarily due to the February 2021 severe winter weather event.

- **Margins from Off-system Sales** increased $10 million primarily due to the following:
  - A $32 million increase at I&M primarily due to Rockport Plant, Unit 2 Merchant sales beginning in December 2022 in addition to higher market prices driven by winter storm Elliott.

  These increases were partially offset by:
  - An $11 million decrease at SWEPCo due to a decrease in Turk Plant merchant sales primarily driven by the February 2021 severe winter weather event.
  - A $9 million decrease at KPCo due to a change in the OSS sharing arrangement.
  - A $4 million decrease at APCo due to decreased generation.
- **Transmission Revenues** increased $82 million primarily due to the following:
  - A $61 million increase due to continued investment in transmission assets and increased load.
  - A $16 million increase in formula rate true-up activity.
- **Other Revenues** increased $31 million primarily due to the following:
  - A $12 million increase due to pole attachment revenue primarily at APCo. This increase was partially offset in Other Operation and Maintenance Expense below.
  - A $10 million increase due to business development revenue primarily at APCo. This increase was partially offset in Other Operation and Maintenance Expense below.
  - A $4 million increase due to a gain on sale of allowances primarily at I&M. The gain on sale of allowances was partially offset in Retail Margins above.
  - A $4 million increase at I&M due to an increase in barging revenues by River Transportation Division (RTD). The increase in barging revenues was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $244 million primarily due to the following:
  - A $131 million increase in PJM transmission services. This increase was partially offset in Retail Margins above.
  - A $69 million increase in generation expenses primarily due to outages and maintenance at APCo, I&M and PSO.
  - A $40 million increase due to a charitable contribution to the AEP Foundation.
  - A $29 million increase in storm restoration expenses.
  - A $25 million increase in distribution expenses primarily related to vegetation management, pole inspections and distribution overhead costs.
  - A $22 million increase in SPP transmission services. This increase was partially offset in Retail Margins above.
  - A $17 million increase in Energy Efficiency/Demand Response expenses. This increase was offset in Retail Margins above.
  - A $14 million increase in accounts receivable factoring expenses as a result of increased interest rates.

  These increases were partially offset by:
  - A $132 million decrease due to the modification of the Rockport Plant, Unit 2 lease which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 at AEGCo and I&M. This decrease was offset in Depreciation and Amortization expense below.
- **Asset Impairments and Other Related Charges** increased $13 million primarily due to:
  - A $25 million increase at APCo due to the write-off of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to the 2017-2019 Virginia Triennial review.

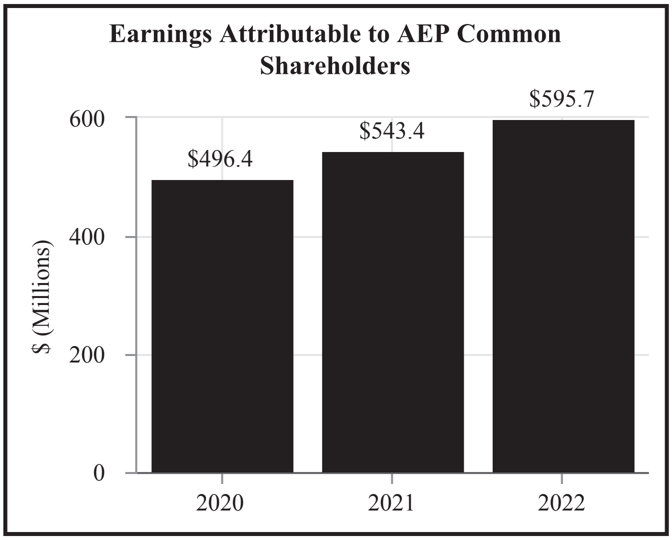
  This increase was partially offset by:
  - A $12 million decrease due to a partial regulatory disallowance of SWEPCo's investment in the Dolet Hills Power Station as a result of an order received in the 2020 Texas Base Rate Case.

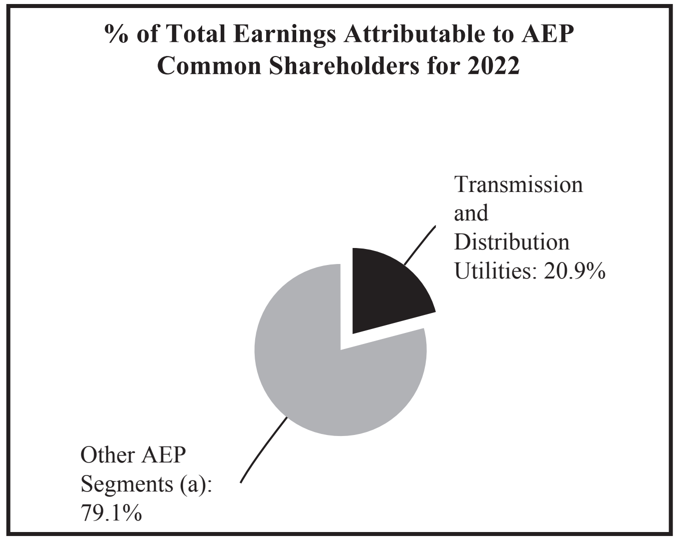
- **Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset** increased $37 million at APCo due to the establishment of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion and resulting from under-earning during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $260 million primarily due to the following:
  - A $132 million increase due to the modification of the Rockport Plant, Unit 2 lease which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 at AEGCo and I&M. This increase was partially offset in Other Operation and Maintenance expenses above.
  - A $128 million increase due to a higher depreciable base primarily at APCo, I&M, PSO and SWEPCo, the implementation of new rates and the timing of refunds to customers under rate rider mechanisms at PSO and in Arkansas and Texas for SWEPCo. The increase due to implementation of new rates and the timing of refunds to customers under rate rider mechanisms at PSO was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to the following:
  - A $17 million increase at PSO and SWEPCo primarily due to increased property taxes and a new infrastructure fee at PSO implemented by the City of Tulsa in March 2022. This increase was partially offset in Retail Margins above.
  - A $4 million increase at APCo primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.

  These increases were partially offset by:
  - A $14 million decrease at I&M primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022. This decrease was partially offset in Retail Margins above.
- **Other Income** increased $17 million primarily due to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event at PSO and SWEPCo.
- **Allowance for Equity Funds Used During Construction** decreased $11 million primarily due to a lower AFUDC base at APCo and SWEPCo and a decrease in AFUDC equity rates primarily at APCo and I&M.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $42 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $77 million primarily due to higher long-term debt balances at APCo, PSO and SWEPCo, higher interest rates at APCo and increased Advances from Affiliates at PSO and SWEPCo.
- **Income Tax Benefit** increased $83 million primarily due to the following:
  - A $92 million increase in PTCs related to enacted legislation under the IRA and additional capital investment in tax-credit eligible property. This increase was partially offset in Retail Margins above.
  - A $16 million increase due to favorable tax return to provision adjustments recorded in the current year.
  - A $15 million increase due to a decrease in flow through depreciation expense.
  - A $7 million increase due to an unfavorable out of period adjustment recorded in the prior year related to deferred income taxes.

  These increases were partially offset by:
  - A $21 million decrease due to an increase in pretax book income.
  - A $19 million decrease due to a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was partially offset in Gross Margin above.

TRANSMISSION AND DISTRIBUTION UTILITIES





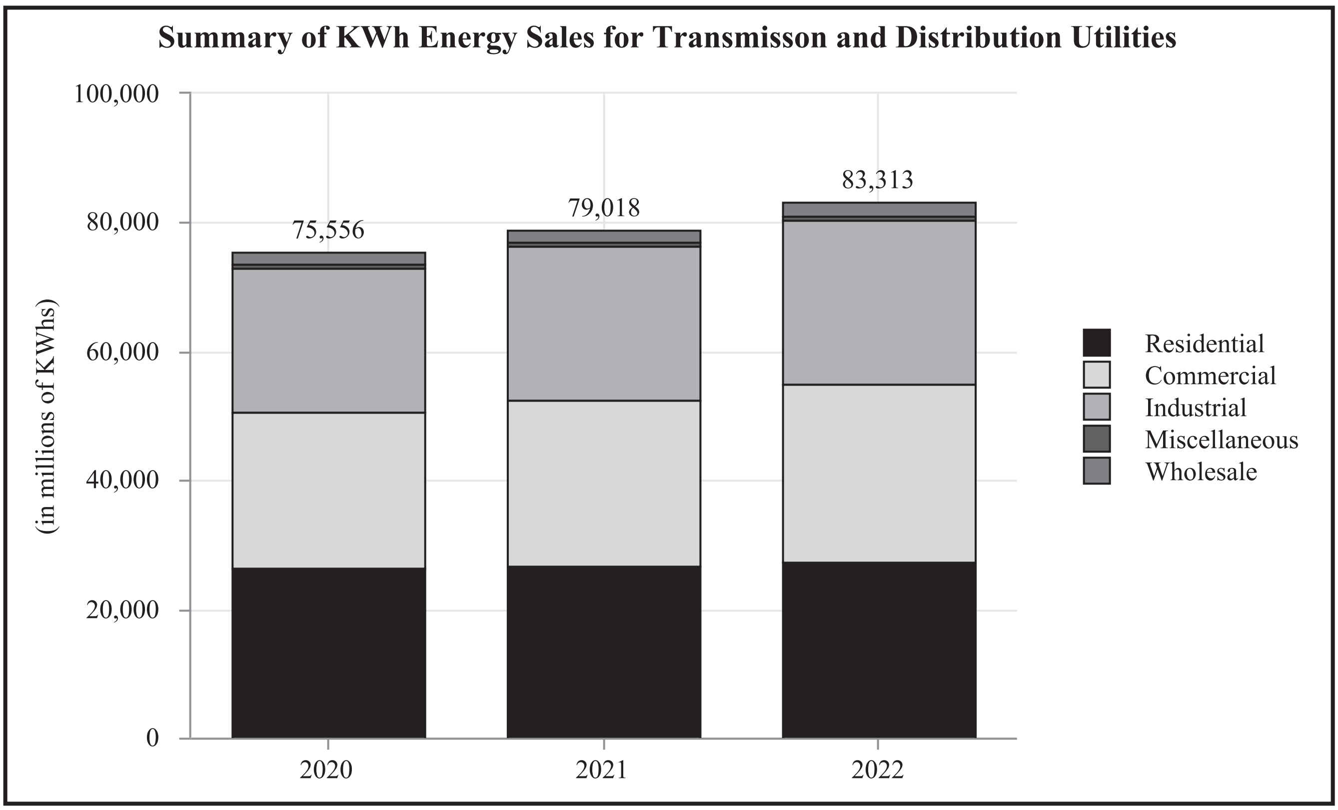
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Transmission and Distribution Utilities	Years Ended December 31, 2022	2021	2020
		(in millions)	
Revenues	$ 5,512.0	$ 4,492.9	$ 4,345.9
Purchased Electricity	1,287.3	729.9	682.7
Gross Margin	4,224.7	3,763.0	3,663.2
Other Operation and Maintenance	1,864.2	1,573.9	1,575.4
Depreciation and Amortization	746.7	690.3	751.1
Taxes Other Than Income Taxes	659.9	640.9	586.7
Operating Income	953.9	857.9	750.0
Other Income	4.9	2.6	4.0
Allowance for Equity Funds Used During Construction	33.6	32.3	31.9
Non-Service Cost Components of Net Periodic Benefit Cost	47.6	29.0	29.4
Interest Expense	(328.0)	(300.9)	(289.2)
Income Before Income Tax Expense and Equity Earnings	712.0	620.9	526.1
Income Tax Expense	116.9	77.5	29.7
Equity Earnings of Unconsolidated Subsidiary	0.6	—	—
Net Income	595.7	543.4	496.4
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 595.7	$ 543.4	$ 496.4

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2022	2021	2020
	(in millions of KWhs)		
Retail:			
Residential	27,479	26,830	26,518
Commercial	27,448	25,514	23,998
Industrial	25,435	23,919	22,432
Miscellaneous	753	737	749
Total Retail (a)	81,115	77,000	73,697
Wholesale (b)	2,198	2,018	1,859
Total KWhs	83,313	79,018	75,556

(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.

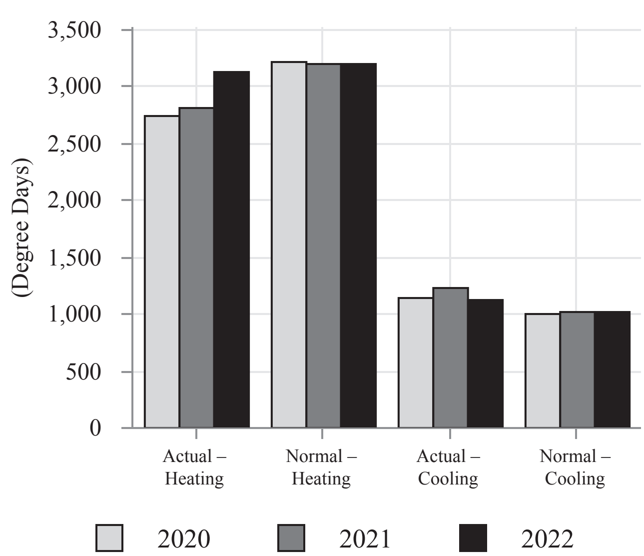
Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

	Years Ended December 31,		
	2022	2021	2020
		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,116	2,815	2,743
Normal – Heating (b)	3,185	3,190	3,202
Actual – Cooling (c)	1,121	1,222	1,140
Normal – Cooling (b)	1,011	1,016	1,006
Western Region			
Actual – Heating (a)	450	341	189
Normal – Heating (b)	312	310	313
Actual – Cooling (d)	2,984	2,653	2,846
Normal – Cooling (b)	2,714	2,712	2,711

(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.

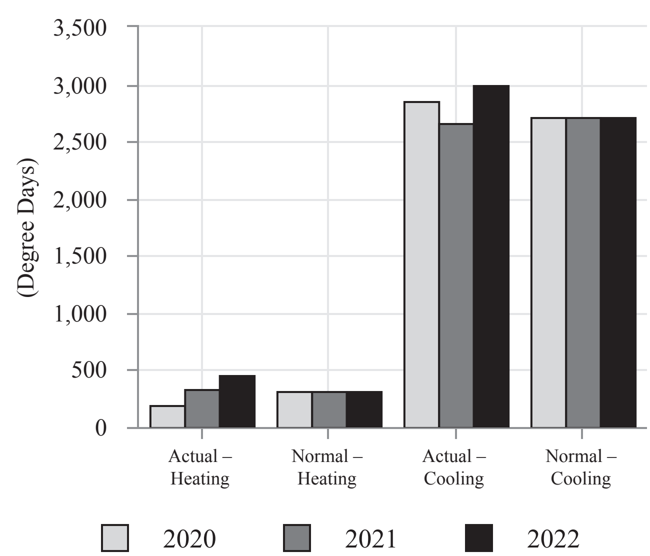
Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

Eastern Region Degree Days



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

Western Region Degree Days



2022 Compared to 2021

Reconciliation of Year Ended December 31, 2021 to Year Ended December 31, 2022
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2021	$	543.4
Changes in Gross Margin:		
Retail Margins		362.3
Margins from Off-system Sales		61.9
Transmission Revenues		72.6
Other Revenues		(35.1)
Total Change in Gross Margin		461.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(290.3)
Depreciation and Amortization		(56.4)
Taxes Other Than Income Taxes		(19.0)
Other Income		2.3
Allowance for Equity Funds Used During Construction		1.3
Non-Service Cost Components of Net Periodic Benefit Cost		18.6
Interest Expense		(27.1)
Total Change in Expenses and Other		(370.6)
Income Tax Expense		(39.4)
Equity Earnings of Unconsolidated Subsidiaries		0.6
Year Ended December 31, 2022	$	595.7

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

- **Retail Margins** increased $362 million primarily due to the following:
  - A $111 million increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses in Ohio. This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $105 million increase due to interim rate increases driven by increased distribution and transmission investment in Texas.
  - A $42 million increase due to various rider revenues in Ohio. This increase was partially offset in Margins from Off-system Sales, Other Revenues and other expense items below.
  - A $30 million increase due to prior year refunds of Excess ADIT to customers in Texas. This increase was partially offset in Income Tax Expense below.
  - A $23 million increase in weather-related usage in Texas primarily due to a 12% increase in cooling degree days and a 32% increase in heating degree days.
  - A $19 million increase in revenue from rate riders in Texas. This increase was partially offset in other expense items below.
  - An $18 million increase in weather-normalized margins primarily in the commercial and industrial classes, partially offset by the residential class.
  - A $10 million increase in weather-related usage in Ohio primarily due to the end of decoupling.

- **Margins from Off-system Sales** increased $62 million primarily due to the following:
  - A $52 million increase in off-system sales at OVEC due to higher market prices and volume, partially offset by an increase in PJM expenses driven by winter storm Elliott. This increase was offset in Retail Margins above and Other Revenues below.
  - A $10 million increase in deferrals of OVEC costs. This increase was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** increased $73 million primarily due to the following:
  - A $65 million increase due to interim rate increases driven by increased transmission investment.
  - A $7 million increase due to prior year refunds to customers in Texas associated with the last base rate case. This increase was offset in Other Revenues below.
- **Other Revenues** decreased $35 million primarily due to the following:
  - A $38 million decrease in Ohio primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This decrease was offset in Retail Margins and Margins from Off-system Sales above.
  - A $12 million decrease in Texas due to the prior year amortization of a provision for refund recorded associated with the last base rate case. This decrease was offset in Retail Margins and Transmission Revenues above.
  - A $7 million decrease in energy efficiency revenues in Texas.

  These decreases were partially offset by:
  - A $26 million increase in securitization revenues primarily due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset in Depreciation and Amortization expenses and Interest Expense below.

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

- **Other Operation and Maintenance** expenses increased $290 million primarily due to the following:
  - An $87 million increase in transmission expenses in Ohio primarily due to the following:
    - An $88 million increase in recoverable PJM expenses. This increase was offset in Retail Margins above.
    - A $3 million increase in transmission vegetation management expenses.

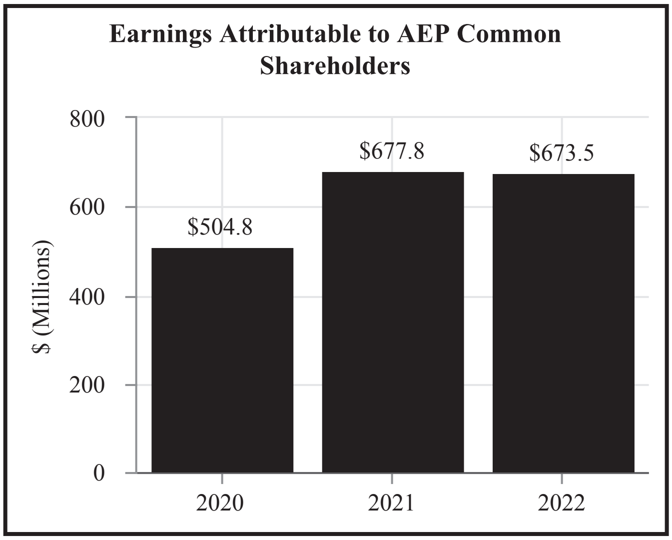
    These increases were partially offset by:
    - A $6 million decrease in transmission formula rate true-up activity.
  - A $76 million increase in ERCOT transmission expenses. This increase was partially offset in Retail Margins and Transmission Revenues above.
  - A $21 million increase in bad debt related expenses in Ohio, including $8 million in 2022 related to Bad Debt Rider over-recovery. This increase was offset in Retail Margins above.
  - A $19 million increase in remitted Universal Service Fund surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
  - An $18 million increase due to a charitable contribution to the AEP Foundation.
  - A $17 million increase in recoverable distribution expenses in Ohio primarily related to vegetation management. This increase was offset in Retail Margins above.
  - A $17 million increase in employee-related expenses.
  - An $11 million increase in distribution-related expenses in Texas.
- **Depreciation and Amortization** expenses increased $56 million primarily due to the following:
  - A $29 million increase due to a higher depreciable base in Texas.
  - A $27 million increase in securitization amortizations in Texas primarily related to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset in Other Revenues above.
  - A $7 million increase in recoverable advanced metering system depreciable expenses in Texas.

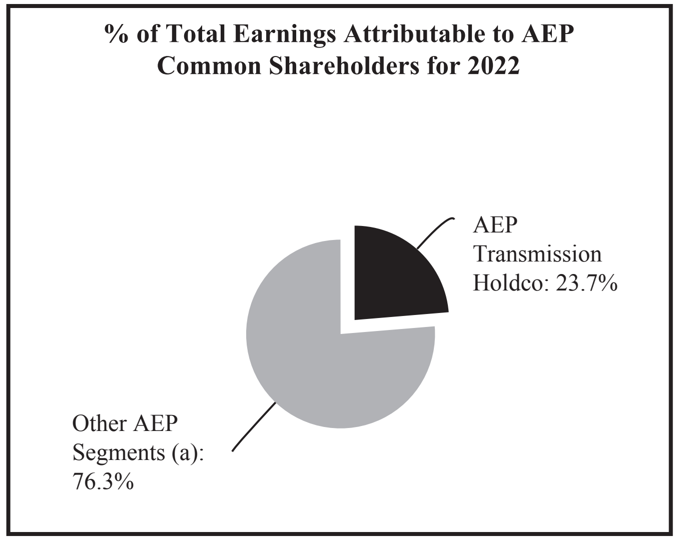
  These increases were partially offset by:
  - A $9 million decrease in recoverable smart grid and Distribution Investment Rider depreciable expenses in Ohio. This decrease was offset in Retail Margins above.

- **Taxes Other Than Income Taxes** increased $19 million primarily due to an increase in Ohio in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Non-Service Cost Components of Net Period Benefit Cost** decreased $19 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $27 million primarily due to the following:
  - A $32 million increase in Texas primarily due to higher long-term debt balances and higher interest rates.

  This increase was partially offset by:
  - A $5 million decrease in Ohio primarily due to the retirement of a higher rate bond, partially offset by the issuance of a lower rate bond in 2021.
- **Income Tax Expense** increased $39 million primarily due to the following:
  - A $21 million decrease in amortization of Excess ADIT. This decrease was partially offset in Gross Margin above.
  - A $19 million increase due to an increase in pretax book income.
  - A $4 million increase due to a current year change in the accounting policy for the parent company loss benefit.

  These increases were partially offset by:
  - A $9 million decrease due to an unfavorable out of period adjustment recorded in the prior year related to deferred income taxes.



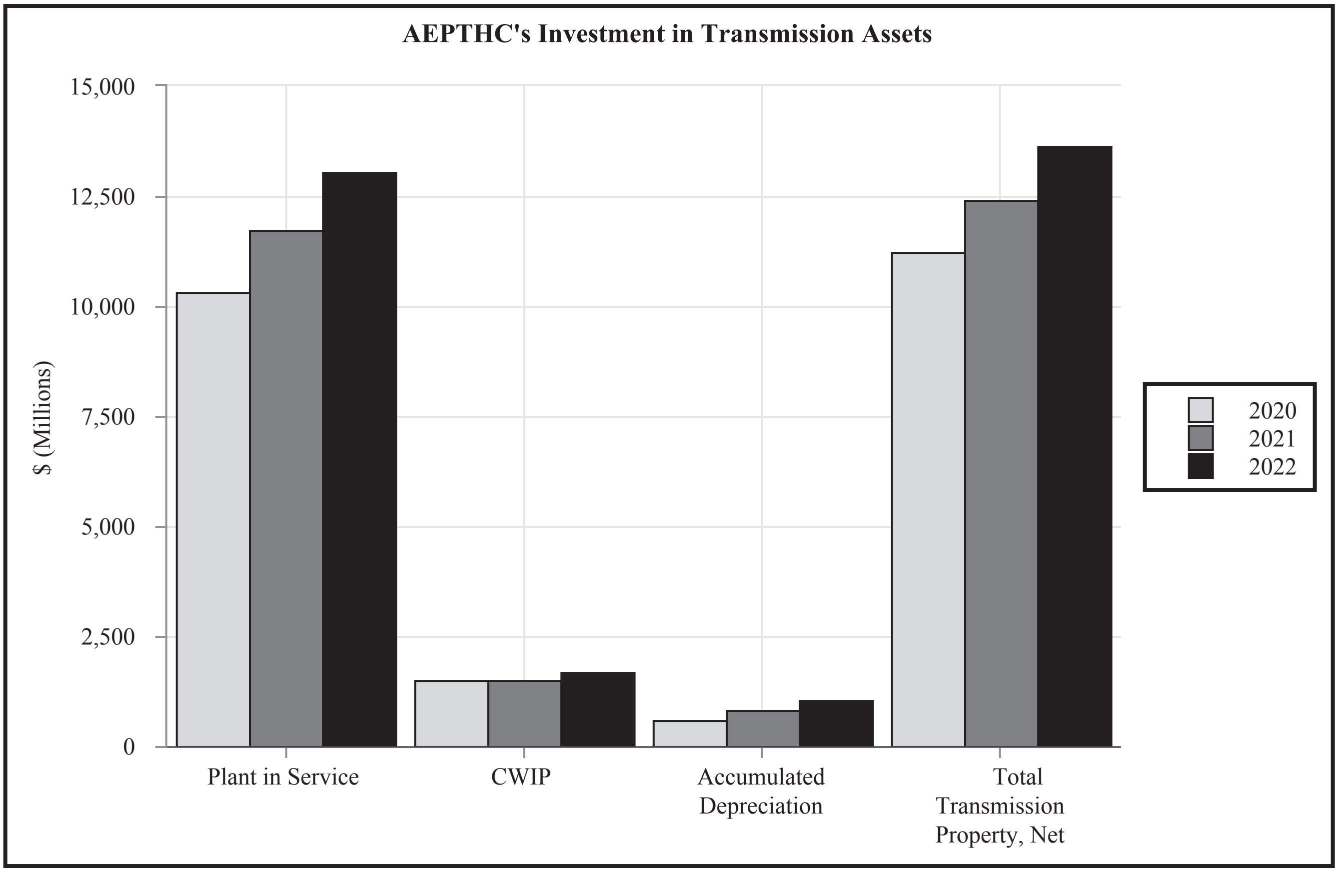


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

AEP Transmission Holdco	Years Ended December 31, 2022	2021	2020
		(in millions)	
Transmission Revenues	$ 1,677.0	$ 1,526.2	$ 1,198.8
Other Operation and Maintenance	165.7	132.3	119.0
Depreciation and Amortization	355.0	306.0	257.6
Taxes Other Than Income Taxes	277.6	245.0	211.0
Operating Income	878.7	842.9	611.2
Interest and Investment Income	2.0	0.7	2.9
Allowance for Equity Funds Used During Construction	70.6	67.2	74.0
Non-Service Cost Components of Net Periodic Benefit Cost	5.0	2.1	2.0
Interest Expense	(169.3)	(146.3)	(133.2)
Income Before Income Tax Expense and Equity Earnings	787.0	766.6	556.9
Income Tax Expense	193.6	159.6	130.8
Equity Earnings of Unconsolidated Subsidiary	83.4	75.0	82.4
Net Income	676.8	682.0	508.5
Net Income Attributable to Noncontrolling Interests	3.3	4.2	3.7
Earnings Attributable to AEP Common Shareholders	$ 673.5	$ 677.8	$ 504.8

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2022	December 31, 2021	December 31, 2020
	(in millions)		
Plant in Service	$ 13,040.2	$ 11,718.0	$ 10,327.5
Construction Work in Progress	1,659.9	1,495.0	1,499.7
Accumulated Depreciation and Amortization	1,047.6	801.8	595.7
Total Transmission Property, Net	$ 13,652.5	$ 12,411.2	$ 11,231.5



2022 Compared to 2021

Reconciliation of Year Ended December 31, 2021 to Year Ended December 31, 2022
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2021	$	677.8
Changes in Transmission Revenues:		
Transmission Revenues		150.8
Total Change in Transmission Revenues		150.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(33.4)
Depreciation and Amortization		(49.0)
Taxes Other Than Income Taxes		(32.6)
Interest and Investment Income		1.3
Allowance for Equity Funds Used During Construction		3.4
Non-Service Cost Components of Net Periodic Pension Cost		2.9
Interest Expense		(23.0)
Total Change in Expenses and Other		(130.4)
Income Tax Expense		(34.0)
Equity Earnings of Unconsolidated Subsidiary		8.4
Net Income Attributable to Noncontrolling Interests		0.9
Year Ended December 31, 2022	$	673.5

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

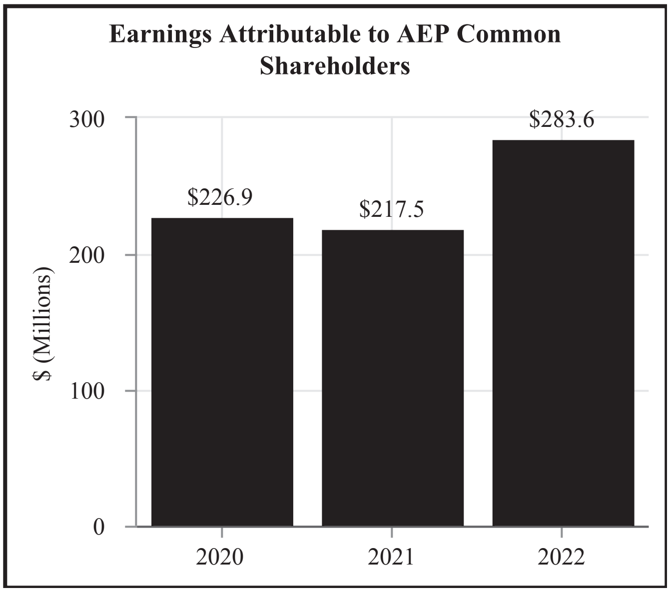
- **Transmission Revenues** increased $151 million primarily due to the following:
  - A $180 million increase due to continued investment in transmission assets.

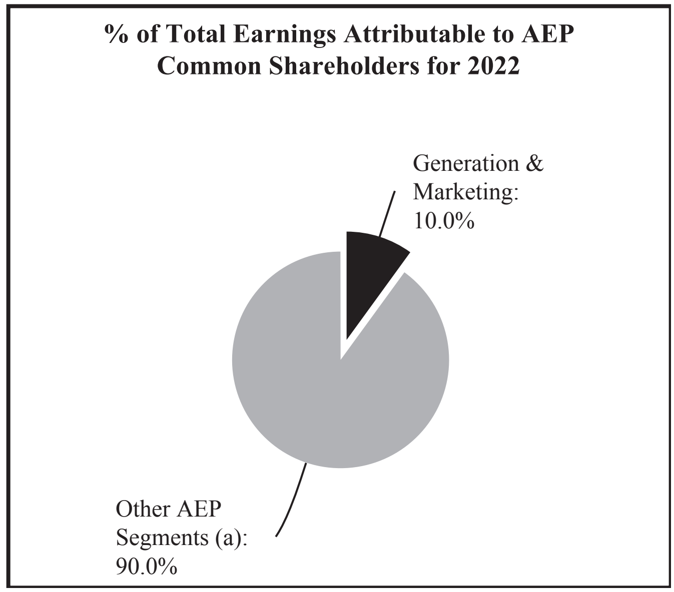
  This increase was partially offset by:
  - A $14 million decrease due to affiliated transmission formula rate true-up activity. This decrease was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $5 million decrease due to nonaffiliated transmission formula rate true-up activity.

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

- **Other Operation and Maintenance** expenses increased $33 million primarily due to the following:
  - A $12 million increase in employee-related expenses.
  - An $11 million increase due to a charitable contribution to the AEP Foundation.
  - A $5 million increase due to cancelled capital projects.
- **Depreciation and Amortization** expenses increased $49 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $33 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $3 million primarily due to higher CWIP.
- **Interest Expense** increased $23 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $34 million primarily due to the following:
  - A $21 million increase due to a current year change in the accounting policy for the parent company loss benefit.
  - A $7 million increase due to an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiary** increased $8 million primarily due to higher pretax equity earnings for ETT and PATH-WV, partially offset by lower pretax equity earnings for Pioneer.

GENERATION & MARKETING



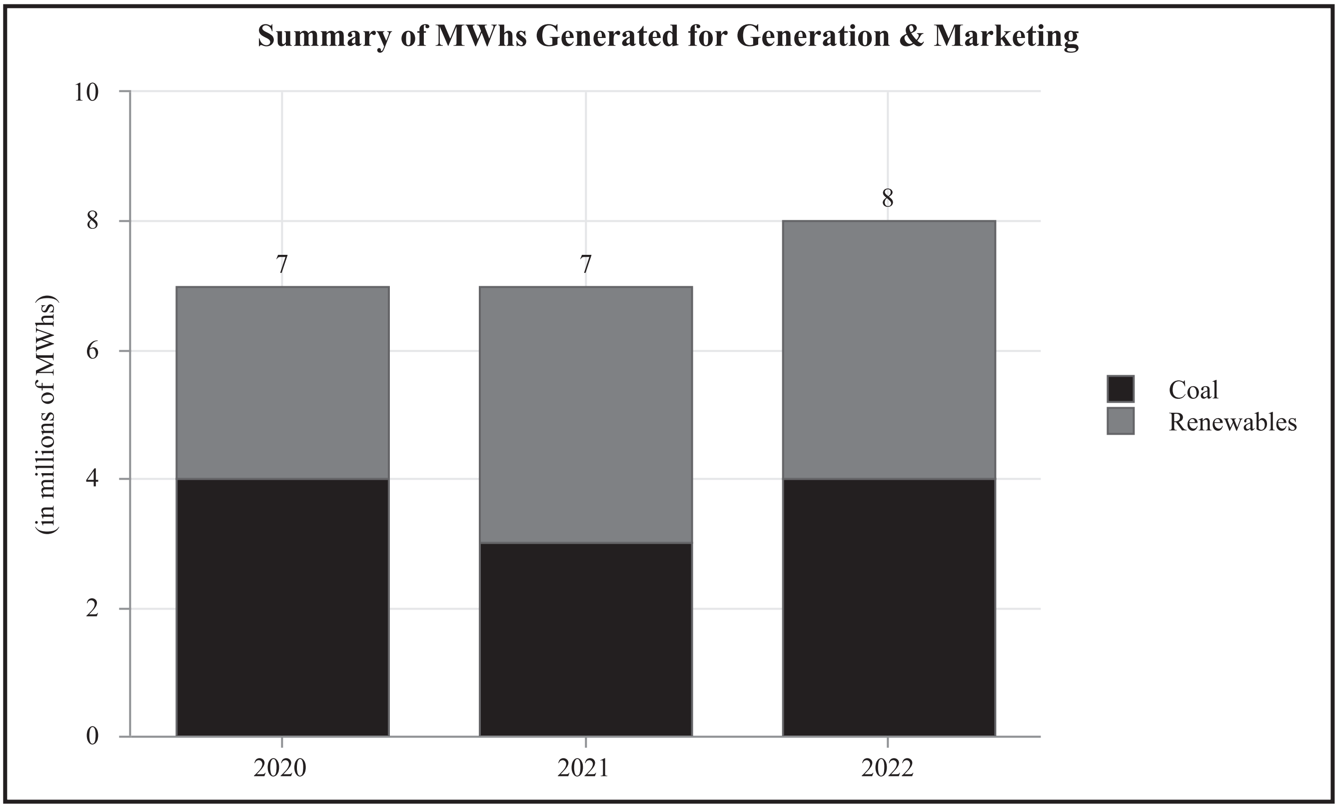


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Generation & Marketing	Years Ended December 31, 2022	2021	2020
		(in millions)	
Revenues	$ 2,466.9	$ 2,163.7	$ 1,725.6
Fuel, Purchased Electricity and Other	1,984.3	1,806.8	1,403.6
Gross Margin	482.6	356.9	322.0
Other Operation and Maintenance	118.7	97.5	124.9
Gain on Sale of Mineral Rights	(116.3)	—	—
Depreciation and Amortization	93.0	80.9	72.8
Taxes Other Than Income Taxes	11.1	10.5	13.2
Operating Income	376.1	168.0	111.1
Interest and Investment Income	38.9	4.2	3.2
Non-Service Cost Components of Net Periodic Benefit Cost	20.6	15.4	15.4
Interest Expense	(51.8)	(15.6)	(24.0)
Income Before Income Tax Benefit and Equity Earnings (Loss)	383.8	172.0	105.7
Income Tax Benefit	(83.1)	(48.8)	(108.0)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(192.4)	(10.6)	3.2
Net Income	274.5	210.2	216.9
Net Loss Attributable to Noncontrolling Interests	(9.1)	(7.3)	(10.0)
Earnings Attributable to AEP Common Shareholders	$ 283.6	$ 217.5	$ 226.9

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31,		
	2022	2021	2020
	(in millions of MWhs)		
Fuel Type:			
Coal	4	3	4
Renewables	4	4	3
Total MWhs	8	7	7



2022 Compared to 2021

Reconciliation of Year Ended December 31, 2021 to Year Ended December 31, 2022
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2021	$	217.5
Changes in Gross Margin:		
Merchant Generation		31.6
Renewable Generation		38.7
Retail, Trading and Marketing		55.4
Total Change in Gross Margin		125.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(21.2)
Gain on Sale of Mineral Rights		116.3
Depreciation and Amortization		(12.1)
Taxes Other Than Income Taxes		(0.6)
Interest and Investment Income		34.7
Non-Service Cost Components of Net Periodic Benefit Cost		5.2
Interest Expense		(36.2)
Total Change in Expenses and Other		86.1
Income Tax Benefit		34.3
Equity Earnings of Unconsolidated Subsidiaries		(181.8)
Net Loss Attributable to Noncontrolling Interests		1.8
Year Ended December 31, 2022	$	283.6

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

- **Merchant Generation** increased $32 million primarily due to higher market prices.
- **Renewable Generation** increased $39 million primarily due to higher market prices at Texas wind facilities and new solar projects placed in service.
- **Retail, Trading and Marketing** increased $55 million primarily due to higher retail power and gas margins.

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

- **Other Operation and Maintenance** expenses increased $21 million primarily due to the following:
  - A $39 million increase due to the sale of Racine Hydro in 2021.
  - A $14 million increase due to newly placed in service renewable projects in 2022.

  These increases were partially offset by:
  - A $33 million decrease due to higher land sales and sale of renewable development projects in 2022.
- **Gain on Sale of Mineral Rights** increased $116 million due to the current year sale of mineral rights.
- **Depreciation and Amortization** expenses increased $12 million primarily due to a higher depreciable base from increased investments in renewable energy assets.
- **Interest and Investment Income** increased $35 million primarily due to an increase in advances to affiliates and higher interest rates in 2022.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $5 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.

- **Interest Expense** increased $36 million primarily due to higher interest rates in 2022.
- **Income Tax Benefit** increased $34 million primarily due to the following:
  - A $22 million increase due to a change in state apportionment impacting deferred state taxes.
  - A $14 million increase due to an unfavorable out of period adjustment recorded in the prior year related to deferred income taxes.
  - A $10 million increase due to a decrease in state taxes.
  - A $7 million increase due to an increase in PTCs related to enacted legislation under the IRA and additional capital investment in tax-credit eligible property.

  These increases were partially offset by:
  - A $10 million decrease due to a current year change in the accounting policy for the parent company loss benefit.
  - An $8 million decrease due to an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $182 million primarily due to the impairment of AEP's investment in Flat Ridge 2 Wind LLC.

CORPORATE AND OTHER

2022 Compared to 2021

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $64 million in 2021 to a loss of $538 million in 2022 primarily due to:

- A $363 million pretax loss related to the anticipated sale of Kentucky operations.
- A $128 million increase in interest expense due to higher interest rates on short-term debt, an increase in advances from affiliates and an increase in long-term debt outstanding.
- A $42 million decrease at EIS, primarily due to lower returns on investments and an increase in reserves.
- A $26 million decrease in equity earnings.
- A $24 million decrease due to asset impairments and other related charges.
- An $18 million decrease due to unfavorable changes in gains and losses from AEP's investment in ChargePoint. As of August 2022, AEP no longer has a direct investment in ChargePoint.

These items were partially offset by:

- A $60 million increase in interest income, primarily due to higher interest income from affiliates.
- A $67 million decrease in Income Tax Expense primarily due to the following:
  - A $66 million decrease due to a loss on the anticipated sale of Kentucky operations.
  - A $40 million decrease due to a current year change in the accounting policy for the parent company loss benefit.
  - A $38 million decrease due to a change in pretax book income.

  These items were partially offset by:
  - A $79 million increase due to an out of period adjustment related to deferred taxes in 2021.

AEP SYSTEM INCOME TAXES

2022 Compared to 2021

- **Income Tax Expense** decreased $110 million primarily due to the following:
  - An $88 million increase in tax credits primarily due to an increase in PTCs related to enacted legislation under the IRA and additional capital investment in tax-credit eligible property.
  - A $61 million decrease due to a decrease in pretax book income.
  - A $42 million decrease due to a change in state apportionment and statutory rates related to deferred taxes.
  - A $17 million decrease in state income taxes primarily due to state return to provision adjustments.

  These decreases were partially offset by:
  - A $55 million increase due to an out of period adjustment recorded in 2021 related to deferred taxes.
  - A $41 million decrease in the amortization of Excess ADIT.

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 Kentucky operations sale, 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, 2022, 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.

The AEP System has 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, 2022, AEP expected to make contributions to the pension plans totaling $6 million in 2023. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 101% funded as of December 31, 2022. 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, 2022		December 31, 2021	
	(dollars in millions)			
Long-term Debt, including amounts due within one year (a)	$ 35,622.6	55.8 %	$ 33,454.5	57.0 %
Short-term Debt	4,112.2	6.4	2,614.0	4.4
Total Debt	39,734.8	62.2	36,068.5	61.4
AEP Common Equity	23,893.4	37.4	22,433.2	38.2
Noncontrolling Interests	229.0	0.4	247.0	0.4
Total Debt and Equity Capitalization	$ 63,857.2	100.0 %	$ 58,748.7	100.0 %

(a) Amount excludes $1.2 billion and $1.1 billion of Total Long-term Debt Outstanding classified as Liabilities Held for Sale on the balance sheet as of December 31, 2022 and 2021, respectively. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

AEP's ratio of debt-to-total capital increased from 61.4% to 62.2% as of December 31, 2021 and 2022, respectively, primarily due to an increase in debt to support distribution, transmission and renewable investment growth in addition to working capital needs due to an increase in deferred fuel costs.

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, 2022, 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 the Federal Reserve continues to raise short-term interest rates, it could reduce future net income and cash flows and impact financial condition. In February 2021, severe winter weather impacted certain AEP service territories resulting in disruptions to SPP market conditions. See Note 4 - Rate Matters for additional information. In March 2021, AEP entered into a $500 million 364-day Term Loan and borrowed the full amount to help address the cash flow implications resulting from the February 2021 severe winter weather event. In August 2022, AEP paid off the $500 million Term Loan. In 2022, increased fuel and purchased power prices continue to lead to an increase in under collection of fuel costs. As a result, in July 2022, APCo and KPCo entered into term loans of $100 million and $75 million, respectively, to help address the cash flow implications of the increased fuel and purchased power costs. See "Deferred Fuel Costs" section of Executive Overview for additional information on how the registrants are addressing the increase in deferred fuel regulatory assets. In September 2022, the ODFA issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for $687 million of extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event. See Note 4 - Rate Matters for additional information. In December 2022, AEP entered into four individual Term Loans, including three 364-day Term Loans, totaling $500 million to further address the cash flow implications of increased fuel and purchased power prices. In February 2023, AEP entered into a $500 million term loan to address short-term liquidity needs, made a capital contribution to SWEPCo, totaling $25 million, for general corporate business purposes and made a capital contribution to AEPTCo, totaling $25 million, to manage short-term borrowing capacity under the Money Pool.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2022, available liquidity was approximately $2.6 billion as illustrated in the table below:

	Amount (in millions)	Maturity	
Commercial Paper Backup:			
Revolving Credit Facility	$ 4,000.0	March 2027	(a)
Revolving Credit Facility	1,000.0	March 2024	(a)
Cash and Cash Equivalents	509.4		
Total Liquidity Sources	5,509.4		
Less: AEP Commercial Paper Outstanding	2,862.2		
Net Available Liquidity	$ 2,647.2		

(a) In April 2022, AEP extended the maturity dates of the Revolving Credit Facilities from March 2026 to March 2027 and from March 2023 to March 2024, respectively.

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 2022 was $2.9 billion. The weighted-average interest rate for AEP's commercial paper during 2022 was 2.74%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under five uncommitted facilities totaling, as of December 31, 2022, $400 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities, as of December 31, 2022, was $287 million with maturities ranging from January 2023 to December 2023.

Financing Plan

As of December 31, 2022, AEP had $2 billion of long-term debt due within one year, excluding $490 million classified as Liabilities Held for Sale on the balance sheet. This also included $250 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 $210 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 $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility. The $125 million facility was renewed in September 2022 and amended to extend the expiration date to September 2024. The $625 million facility also expires in September 2024. As of December 31, 2022, the affiliated utility subsidiaries, with the exception of SWEPCo, were in compliance with all requirements under the agreement. SWEPCo temporarily eased credit policies from August 2022 through October 2022 to assist customers with higher than normal bills driven by increased fuel costs and, in turn, experienced higher than normal aged receivables. In response, in January 2023, AEP Credit amended its receivables securitization agreement to increase the eligibility criteria related to their aged receivables requirements to bring SWEPCo back into compliance.

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, 2022, this contractually-defined percentage was 59.1%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

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

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

ATM Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, up to an aggregate of $1 billion of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. There were no issuances under the ATM program for the year ended December 31, 2022. As of December 31, 2022, approximately $511 million 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 settles after three years in August 2023. The proceeds were used to support AEP's overall capital expenditure plan.

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes due in 2024 and a forward equity purchase contract which settled after three years in 2022. The proceeds from this issuance were used to support AEP's overall capital expenditure plans including the acquisition of Sempra Renewables LLC. In January 2022, AEP successfully remarketed the notes on behalf of holders of the corporate units and did not directly receive any proceeds therefrom. Instead, the holders of the corporate units used the debt remarketing proceeds to settle the forward equity purchase contract with AEP. The interest rate on the notes was reset to 2.031% with the maturity remaining in 2024. In March 2022, AEP issued 8,970,920 shares of AEP common stock and received proceeds totaling $805 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.

See Note 14 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.83 per share in January 2023. 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,		
	2022	**2021**	**2020**
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 451.4	$ 438.3	$ 432.6
Net Cash Flows from Operating Activities	5,288.0	3,839.9	3,832.9
Net Cash Flows Used for Investing Activities	(7,751.8)	(6,433.9)	(6,233.9)
Net Cash Flows from Financing Activities	2,568.9	2,607.1	2,406.7
Net Increase in Cash, Cash Equivalents and Restricted Cash	105.1	13.1	5.7
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 556.5	$ 451.4	$ 438.3

Operating Activities

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 2,305.6	$ 2,488.1	$ 2,196.7
Non-Cash Adjustments to Net Income (a)	3,461.6	3,025.9	2,954.8
Mark-to-Market of Risk Management Contracts	15.5	112.3	66.5
Pension Contributions to Qualified Plan Trust	—	—	(110.3)
Property Taxes	(41.2)	(68.0)	(43.3)
Deferred Fuel Over/Under Recovery, Net	(319.2)	(1,647.9)	(31.8)
Change in Regulatory Assets	(46.7)	(238.9)	(337.9)
Change in Other Noncurrent Assets	(187.7)	(126.6)	(151.0)
Change in Other Noncurrent Liabilities	337.8	206.4	(54.5)
Change in Certain Components of Working Capital	(237.7)	88.6	(656.3)
Net Cash Flows from Operating Activities	$ 5,288.0	$ 3,839.9	$ 3,832.9

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Rockport Plant, Unit 2 Lease Amortization, Deferred Income Taxes, Loss on the Expected Sale of the Kentucky Operations, 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.

2022 Compared to 2021

Net Cash Flows from Operating Activities increased by $1.4 billion primarily due to the following:

- A $1.3 billion increase in cash primarily due to the timing of fuel and purchased power revenues and expenses. PSO and SWEPCo were impacted by the February 2021 severe winter weather event in SPP which led to significantly higher fuel and purchased power expenses which were deferred as regulatory assets in 2021. In September 2022, the ODFA issued ratepayer-backed securitization bonds and provided PSO proceeds of $687 million as reimbursement of the extraordinary fuel costs and purchased electricity incurred during the severe winter weather event. See Note 4 - Rate Matters for additional information. In 2022, increased fuel and purchased power prices in excess of amounts included in fuel-related revenues has resulted in an increase in the under collection of fuel costs in most jurisdictions, offsetting the proceeds received by PSO in September 2022. See the “Deferred Fuel Costs” section of Executive Overview for additional information.
- A $253 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $192 million increase in cash from Changes in Regulatory Assets primarily due to incremental other operation and maintenance storm restoration expenses incurred in 2021 by APCo, SWEPCo and KPCo as a result of the February 2021 severe winter weather event. The increase due to the February 2021 severe winter weather event was partially offset by the deferral of incremental other operation and maintenance storm restoration expenses incurred in June 2022 by APCo, KPCo, OPCo and WPCo. See Note 4 - Rate Matters for additional information.
- A $131 million increase in cash from Changes in Other Noncurrent Liabilities. The increase is primarily due to changes in provisions for refunds and regulatory liabilities driven by timing differences between collections from and refunds to customers under rate rider mechanisms. See Note 5 - Effects of Regulation for additional information.
- A $97 million increase primarily due to collateral held against risk management contracts due to pricing movement in the commodities market.

These increases in cash were offset by:

- A $326 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 and material and supplies in addition to prior year decreases in coal and lignite inventory on hand, an increase in estimated federal income taxes paid and the timing of accounts receivables. These decreases were partially offset by the timing of accounts payable and a return of margin deposits from PJM originally paid in 2021.

Investing Activities

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Construction Expenditures	$ (6,671.7)	$ (5,659.6)	$ (6,246.3)
Acquisitions of Nuclear Fuel	(100.7)	(104.5)	(69.7)
Acquisition of the Dry Lake Solar Project	—	(114.4)	—
Acquisition of the North Central Wind Energy Facilities	(1,207.3)	(652.8)	—
Proceeds on Sale of Assets	218.0	118.9	71.1
Other	9.9	(21.5)	11.0
Net Cash Flows Used for Investing Activities	$ (7,751.8)	$ (6,433.9)	$ (6,233.9)

2022 Compared to 2021

Net Cash Flows Used for Investing Activities increased by $1.3 billion primarily due to the following:

- A $1 billion increase in construction expenditures, primarily due to increases in Vertically Integrated and Transmission and Distribution segments of $647 million and $411 million, respectively.
- A $440 million increase due to the 2022 acquisition of Traverse, partially offset by the 2021 acquisitions of the Dry Lake Solar Project, Sundance and Maverick. See Note 7 - Acquisitions, Assets and Liabilities Held for Sale, Dispositions and Impairments for additional information.

These increases in cash used were partially offset by:

- A $99 million increase in Proceeds from Sale of Assets, primarily due to the 2022 sale of certain mineral rights. See Note 7 - Acquisitions, Assets and Liabilities Held for Sale, Dispositions and Impairments for additional information.

Financing Activities

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Issuance of Common Stock	$ 826.5	$ 600.5	$ 155.0
Issuance/Retirement of Debt, Net	3,802.5	3,631.7	3,927.3
Dividends Paid on Common Stock	(1,645.2)	(1,519.5)	(1,424.9)
Principal Payments for Finance Lease Obligations	(309.5)	(64.0)	(61.7)
Redemption of Noncontrolling Interests	—	—	(100.2)
Other	(105.4)	(41.6)	(88.8)
Net Cash Flows from Financing Activities	$ 2,568.9	$ 2,607.1	$ 2,406.7

2022 Compared to 2021

Net Cash Flows from Financing Activities decreased by $38 million primarily due to the following:

- A $1.8 billion decrease in issuances of long-term debt. See Note 14 - Financing Activities for additional information.
- A $246 million decrease due to an increase in Principal Payments for Finance Lease Obligations primarily driven by Rockport Plant, Unit 2 final lease payments.
- A $126 million decrease due to an increase in dividends paid on common stock.

These decreases in cash were partially offset by:

- A $1.4 billion increase in short-term debt primarily due to increased draws under the commercial paper program. See Note 14 - Financing Activities for additional information.
- A $644 million increase due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $226 million increase in issuances of common stock primarily due to the settlement of the 2019 equity units. See "Equity Units" section of Note 14 for additional information.

The following financing activities occurred during 2022:

AEP Common Stock:

- During 2022, AEP issued 683 thousand shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans. Additionally in 2022, AEP reissued 9 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 $827 million related to these issuances.

Debt:

- During 2022, AEP issued approximately $4.7 billion of long-term debt, including $3.1 billion of senior unsecured notes at interest rates ranging from 4.5% to 5.95%, $1.3 billion of other debt at various interest rates and $214 million of pollution control bonds at interest rates ranging from 3% to 3.75%. The proceeds from these issuances were primarily used to fund long-term debt maturities, construction programs and to help address working capital needs.
- During 2022, AEP entered into interest rate derivatives with notional amounts totaling $700 million that were designated as cash flow hedges. During 2022, settlements of AEP's interest rate derivatives resulted in net cash paid of $7 million for derivatives designated as fair hedges. As of December 31, 2022, AEP had a total notional amount of $950 million of outstanding interest rate derivatives designated as fair value hedges and $700 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, 2022 through February 23, 2023, the date that the 10-K was issued.

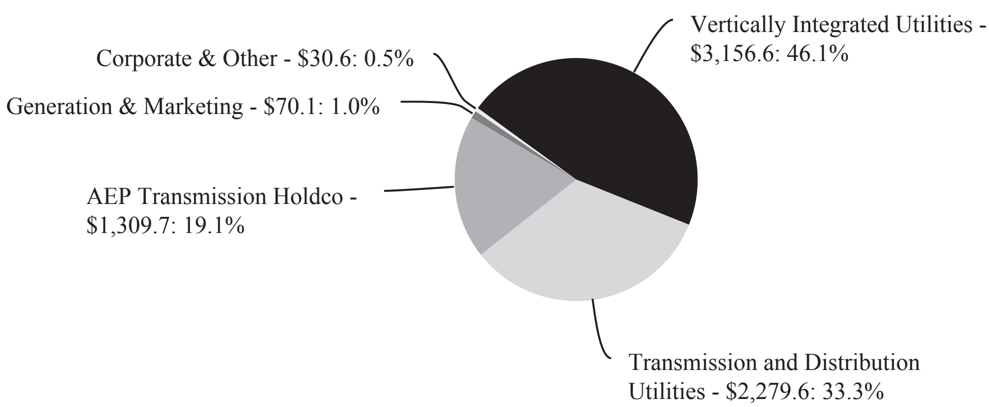
BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $6.8 billion of capital expenditures in 2023. For the four year period, 2024 through 2027, management forecasts capital expenditures of $32.9 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 and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations, proceeds from the sale of Kentucky operations, proceeds from the sale of competitive contracted renewables 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 2023 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2023 Budgeted Capital Expenditures							
Segment	**Environmental**	**Generation**	**Renewables**	**Transmission**	**Distribution**	**Other (a)**	**Total**	
				(in millions)				
Vertically Integrated Utilities	$ 150.7	$ 345.5	$ 106.1	$ 817.3	$ 1,310.7	$ 426.3	$ 3,156.6	(b)
Transmission and Distribution Utilities	—	—	—	999.0	993.1	287.5	2,279.6	
AEP Transmission Holdco	—	—	—	1,290.6	—	19.1	1,309.7	(b)
Generation & Marketing	—	43.9	4.7	—	—	21.5	70.1	
Corporate and Other	—	—	—	—	—	30.6	30.6	
Total	$ 150.7	$ 389.4	$ 110.8	$ 3,106.9	$ 2,303.8	$ 785.0	$ 6,846.6	

(a) Amount primarily consists of facilities, software and telecommunications.
(b) 2023 budgeted capital expenditures do not include any amounts for KPCo or KTCo.

2023 Budgeted Capital Expenditures by Business Segment ($ in millions)



The table below represents estimated capital investments by business segment for the years 2024 to 2027:

Segment	2024	2025	2026	2027
Vertically Integrated Utilities (a)	$ 5,103.6	$ 6,417.2	$ 3,824.9	$ 3,306.3
Transmission and Distribution Utilities	2,509.8	2,280.0	2,289.3	2,226.5
AEP Transmission Holdco (a)	1,225.5	964.5	1,107.1	1,246.4
Generation & Marketing	76.6	72.4	76.4	103.6
Corporate and Other	27.4	14.0	15.4	2.1
Total	$ 8,942.9	$ 9,748.1	$ 7,313.1	$ 6,884.9

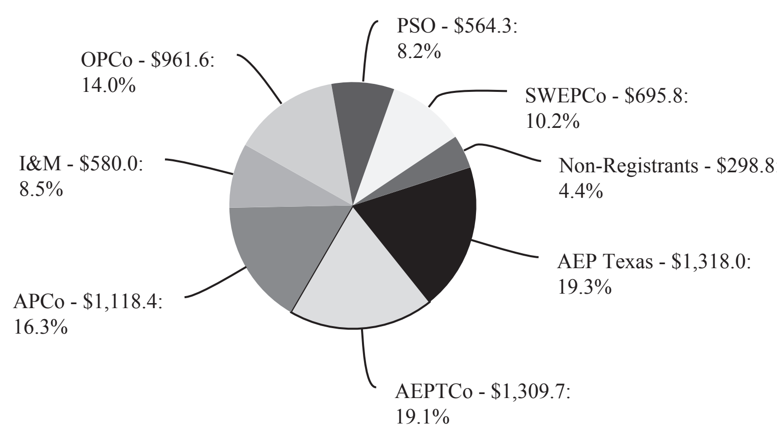
(a) 2024-2027 estimated capital investments do not include any amounts for KPCo or KTCo.

The 2023 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation-related investments, as well as expenditures for compliance with environmental regulations as follows:

	2023 Budgeted Capital Expenditures						
Company	Environmental	Generation	Renewables	Transmission	Distribution	Other (a)	Total
				(in millions)			
AEP Texas	$ —	$ —	$ —	$ 683.3	$ 509.1	$ 125.6	$ 1,318.0
AEPTCo	—	—	—	1,290.6	—	19.1	1,309.7
APCo	65.9	122.8	25.3	324.9	432.8	146.7	1,118.4
I&M	—	100.8	2.0	74.6	297.1	105.5	580.0
OPCo	—	—	—	315.7	484.0	161.9	961.6
PSO	0.2	27.4	57.7	119.2	305.7	54.1	564.3
SWEPCo	4.8	48.1	21.2	290.0	221.3	110.4	695.8

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

2023 Budgeted Capital Expenditures by Registrant Subsidiary
($ in millions)



CYBER SECURITY

The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The NERC, which FERC certified as the nation's Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP's service territory covers multiple NERC regions and is audited at least annually by one or more of the regions. AEP has participated in the NERC grid security and emergency response exercises, GridEx, for the past ten years and continues to participate in the bi-yearly exercises. These NERC-led efforts test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid. AEP also conducts internal exercises to test and further develop AEP's cyber response plans. These internal scenarios are chosen based on real world events and often include coordination with and communication to AEP's Chief Executive Officer and executive team.

The operations of AEP's electric utility subsidiaries are subject to extensive and rigorous mandatory cyber and physical security requirements that are developed and enforced by NERC to protect grid security and reliability. AEP's enterprise-wide security program includes cyber and physical security and incorporates many of the guidelines set forth in the National Institute of Standards and Technology Cybersecurity Framework. AEP's Chief Security Officer (CSO) is also its NERC Critical Infrastructure Protection Senior Manager, ensuring alignment of compliance with the enterprise-wide security program.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security controls and authentication. Cyber hackers and other malicious actors have caused material disruption by successfully breaching a number of very secure facilities, including federal agencies and financial institutions. As understanding of these events develop, AEP has adopted a defense in depth approach to cyber security and continually assesses its cyber security tools and processes to determine where to strengthen its defenses. These strategies include monitoring, alerting and emergency response, forensic analysis, disaster recovery, threat sharing and criminal activity reporting. This approach has allowed AEP to deal with cyber and related threats, intrusions and attempted breaches in real-time and to limit their impact to levels that would be expected in the ordinary course of business in the absence of such malicious activity.

AEP has undertaken a variety of actions to monitor and address cyber-related risks. Cyber security and the effectiveness of AEP's cyber security processes are reviewed annually with the Board of Directors and at several meetings throughout the year with the Technology Committee of the Board, the principal committee that exercises oversight with respect to these matters. AEP's Chief Executive Officer and executive team participate in interactive threat briefings from AEP's CSO and the security leadership team on a regular basis. AEP's strategy and procedure for managing cyber-related risks is integrated within its enterprise risk management processes. These procedures are designed to ensure that any material information regarding potentially relevant cyber incidents is elevated in a timely manner both to the appropriate leadership and, where applicable, to our external financial reporting and disclosure team. AEP's enterprise-wide security program continually adjusts staff and resources in response to the evolving threat landscape. The costs for such investments are material and have remained constant over time, a pattern that is expected to continue. In addition, AEP maintains cyber liability insurance to cover certain damages caused by cyber incidents.

AEP's CSO leads the cyber security and physical security teams and is responsible for the design, implementation and execution of AEP's security risk management strategy, which includes cyber security. AEP's cyber security team operates a 24/7 Cyber Security Intelligence and Response Center responsible for monitoring the AEP System for cyber risks and threats. The cyber security team constantly scans the AEP System for risks and threats. In addition, under the direction of the CSO, the cyber security team actively monitors best practices, performs penetration testing, leads response exercises and internal awareness campaigns and provides training and communication across the organization. AEP's security awareness training is mandatory for all employees and includes regular phish email testing to train employees to identify malicious emails that could put AEP at risk.

AEP also continually reviews its business continuity plan to develop an effective recovery strategy that seeks to decrease response times, limit financial impacts and maintain customer confidence during any business interruption. The cyber security team administers a third-party risk governance program that identifies potential risks introduced through third-party relationships, such as vendors, software and hardware manufacturers or professional service providers. As warranted, AEP obtains certain contractual security guarantees and assurances with these third-party relationships to help ensure the security and safety of its information. The cyber security team works closely with a broad range of departments, including legal, regulatory, corporate communications, audit services, information technology and operational technology functions critical to the power grid.

The cyber security team collaborates with partners from both industry and government, and routinely participates in industry-wide programs that exchange knowledge of threats with utility peers, industry and federal agencies. AEP is an active member of a number of industry-specific threat and information sharing communities including the Department of Homeland Security’s Joint Cyber Defense Collaborative, the Electricity Information Sharing and Analysis Center and the National Defense Information Sharing and Analysis Center. AEP continues to work with nonaffiliated entities to do penetration testing and to design and implement appropriate remediation strategies. There can be no assurance, however, that these efforts will be effective to prevent material interruption of services or other damages to AEP's business or operations in connection with any cyber-related incident.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

Regulatory Accounting

Nature of Estimates Required

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

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

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

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $354 million and $246 million as of December 31, 2022 and 2021, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $108 million, $(42) million and $40 million for the years ended December 31, 2022, 2021 and 2020, 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 $221 million and $172 million as of December 31, 2022 and 2021, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $49 million, $1 million and $5 million for the years ended December 31, 2022, 2021 and 2020, 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 $109 million and $110 million as of December 31, 2022 and 2021, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $(1) million, $24 million and $11 million for the years ended December 31, 2022, 2021 and 2020, 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

AEP 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). AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

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

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

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2022**	**2021**	**2020**
		(in millions)	
Pension Plans	$ 80.9	$ 138.2	$ 108.6
OPEB	(144.8)	(122.0)	(109.7)

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 2023, 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 7.5% for the Qualified Plan and 7.25% for the OPEB plans.

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

	Pension Plans		**OPEB**	
	2023 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2023 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	30 %	9.28 %	59 %	8.30 %
Fixed Income	54	5.92	40	5.71
Other Investments	15	9.06	—	—
Cash and Cash Equivalents	1	2.67	1	2.67
Total	100 %		100 %	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 7.5% for the Qualified Plan and 7.25% 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 loss of 16.88% and a gain of 5.41% for the years ended December 31, 2022 and 2021, respectively. The OPEB plans' assets had an actual loss of 19.53% and a gain of 8.67% for the years ended December 31, 2022 and 2021, 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, 2022, AEP had cumulative gains of approximately $523 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, 2022 under this method was 5.5% for the Qualified Plan, 5.6% for the Nonqualified Plans and 5.5% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return on the Pension Plans' assets of 7.5%, discount rates of 5.5% and 5.6% and various other assumptions, management estimates credits for the Pension Plans will approximate $24 million and $20 million in 2023 and 2024, respectively. Management estimates that the pension costs for the Pension Plans will approximate $8 million in 2025. Based on an expected rate of return on the OPEB plans' assets of 7.25%, a discount rate of 5.5% and various other assumptions, management estimates OPEB plan credits will approximate $107 million, $65 million and $62 million in 2023, 2024 and 2025, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets decreased to $4.1 billion as of December 31, 2022 from $5.4 billion as of December 31, 2021 primarily due to negative investment returns. During 2022, the Qualified Plan paid $395 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of AEP's OPEB plans' assets decreased to $1.5 billion as of December 31, 2022 from $2.0 billion as of December 31, 2021 primarily due to negative investment returns. During 2022, the OPEB plans paid $140 million in benefits to plan participants.

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2022 Benefit Obligations				
Discount Rate	$ (170.2)	$ 184.9	$ (37.1)	$ 40.3
Compensation Increase Rate	19.7	(18.3)	NA	NA
Cash Balance Crediting Rate	57.2	(54.2)	NA	NA
Health Care Cost Trend Rate	NA	NA	6.1	(5.4)
Effect on 2022 Periodic Cost				
Discount Rate	$ (12.7)	$ 14.0	$ 3.0	$ (2.9)
Compensation Increase Rate	7.4	(6.8)	NA	NA
Cash Balance Crediting Rate	14.3	(13.4)	NA	NA
Health Care Cost Trend Rate	NA	NA	0.6	(0.2)
Expected Return on Plan Assets	(24.1)	24.1	(10.1)	10.1

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. The IRS has since released interim guidance in the form of Notices addressing the Prevailing Wage and Apprenticeship Requirements tied to full value PTCs and ITCs for projects that begin construction on or after January 29, 2023, and time-sensitive issues related to the CAMT. 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.

The enactment of the IRA will have future cash flow and income tax reporting considerations. AEP and subsidiaries expect to be applicable CAMT corporations beginning in 2023 and AEP expects to have CAMT cash tax payments beginning in 2024. CAMT cash taxes are expected to be 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 will be presented in the operating section of the cash flow statement consistent with the presentation of cash taxes paid. AEP will present the gain or loss on sale of tax credits through income tax expense on the statement of income. Management believes this presentation provides consistency in financial statement reporting as it matches the originating income tax benefit of the tax credit.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards. There are no new standards expected to have a material impact to the Registrants' financial statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

The Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates.

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the 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 Grid Solutions, 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.

Due to multiple defaults of market participants, ERCOT had a large outstanding unpaid balance associated with the February 2021 winter storm. A certain portion of this balance has been securitized and disbursed to impacted market participants. A recovery plan has been reached by ERCOT for the remaining portion of the outstanding balance. In both cases, financial costs are allocated to certain market participants and in the role AEPEP is exposed, but not materially. If the market rules were to change on how socialized losses are allocated this could affect AEPEP's exposure. Regardless of the approach of how socialized losses are allocated there are potential downstream impacts that could push counterparties into financial distress and or bankruptcy, affecting AEPEP, AEP Texas and ETT.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2021:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2022

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2021	$ 59.8	$ (91.4)	$ 275.9	$ 244.3
(Gain)/Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(75.5)	5.7	(66.0)	(135.8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	0.9	0.9
Changes in Fair Value Due to Market Fluctuations During the Period (b)	10.7	—	149.7	160.4
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	133.7	45.7	—	179.4
MTM Risk Management Contract Net Assets Held for Sale Related to KPCo (d)	(2.5)	—	—	(2.5)
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2022	$ 126.2	$ (40.0)	$ 360.5	446.7
Commodity Cash Flow Hedge Contracts				283.3
Interest Rate Cash Flow Hedge Contracts				11.0
Fair Value Hedge Contracts				(127.4)
Collateral Deposits				(479.6)
Total MTM Derivative Contract Net Assets as of December 31, 2022				$ 134.0

(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.
(d) MTM risk management contract net assets relating to KPCo are classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

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, 2022, credit exposure net of collateral to sub investment grade counterparties was approximately 0.6%, 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, 2022, 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	$ 691.0	$ 236.7	$ 454.3	2	$ 131.2
Split Rating	9.0	—	9.0	1	9.0
Noninvestment Grade	2.3	2.2	0.1	1	0.1
No External Ratings:					
Internal Investment Grade	41.2	—	41.2	2	24.8
Internal Noninvestment Grade	5.2	2.5	2.7	3	2.5
Total as of December 31, 2022	$ 748.7	$ 241.4	$ 507.3		

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, 2022, 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, 2022				Twelve Months Ended December 31, 2021			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.5	$ 4.5	$ 0.7	$ 0.1	$ 0.4	$ 3.6	$ 0.4	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2022				Twelve Months Ended December 31, 2021			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 17.7	$ 76.9	$ 24.7	$ 6.7	$ 8.3	$ 14.9	$ 3.7	$ 0.7

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 rate increases totaling 4.25%. The Federal Reserve has indicated that, in light of continued signs of inflation, it foresees further increases in interest rates in 2023. 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, 2022, 2021 and 2020, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $47 million, $33 million and $32 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, 2022 and 2021 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, 2022, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, 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, 2022 and 2021 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 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, 2022, 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, 2022, there were $5.6 billion of deferred costs included in regulatory assets, $0.8 billion of which were pending final regulatory approval, and $8.0 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 $332.5 million and $180.6 million, as of December 31, 2022, 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.

Classification of the Assets and Liabilities of KPCo and KTCo as Held for Sale

As described in Note 7 to the consolidated financial statements, in October 2021 the Company entered into a Stock Purchase Agreement (SPA) to sell Kentucky Power Company (KPCo) and Kentucky Transmission Company (KTCo) to Liberty Utilities Co. (Liberty) for $2.85 billion. In September 2022, the Company and Liberty entered into an amendment to the SPA which reduced the purchase price to approximately $2.646 billion. The sale is subject to several regulatory approvals, including approval from the Kentucky Public Service Commission (KPSC) and from the Federal Energy Regulatory Commission (FERC). In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to 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 adverse effect on rates. In January 2023, the Company and Liberty entered into an amendment to the SPA that specified the applicants will submit a new filing for approval under Section 203 of the Federal Power Act. The new filing was submitted to the FERC on February 14, 2023. Management believes it is probable that FERC authorization under Section 203 of the Federal Power Act will be received and closing will occur in 2023. Therefore, the assets and liabilities of KPCO and KTCo will continue to be classified as held for sale as of December 31, 2022.

The principal considerations for our determination that performing procedures relating to the classification of the assets and liabilities of KPCo and KTCo is a critical audit matter are the significant judgment by management in determining the classification of the assets and liabilities as held for sale, and in assessing the impact of regulatory 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 that a sale of the assets and liabilities of KPCO and KTCo will occur resulting in held for sale classification as of December 31, 2022.

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 determination of the classification of the assets and liabilities of KPCo and KTCo as held for sale. These procedures also included, among others, evaluating management’s determination of the classification of KPCo and KTCo as held for sale which involved i) evaluating the reasonableness of management's assessment of probability of the sale to occur resulting in held for sale classification as of the balance sheet date ii) evaluating the commitment of both parties to the sale as supported by public statements and other representations, iii) evaluating guidance in applicable regulatory orders and other regulatory correspondence, iv) consideration of relevant regulatory and legal precedents, and v) reviewing written agreements in place between the parties related to the sale.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 23, 2023

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, 2022. 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, 2022.

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, 2022. 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, 2022, 2021 and 2020
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2022	2021	2020
REVENUES			
Vertically Integrated Utilities	$ 11,292.8	$ 9,852.2	$ 8,753.2
Transmission and Distribution Utilities	5,489.6	4,464.1	4,238.7
Generation & Marketing	2,448.9	2,108.3	1,621.0
Other Revenues	408.2	367.4	305.6
TOTAL REVENUES	19,639.5	16,792.0	14,918.5
EXPENSES			
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	7,097.9	5,466.3	4,369.7
Other Operation	2,878.1	2,547.7	2,572.4
Maintenance	1,249.4	1,121.8	1,010.4
Loss on the Expected Sale of the Kentucky Operations	363.3	—	—
Asset Impairments and Other Related Charges	48.8	11.6	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	—
Gain on Sale of Mineral Rights	(116.3)	—	—
Depreciation and Amortization	3,202.8	2,825.7	2,682.8
Taxes Other Than Income Taxes	1,469.8	1,407.6	1,295.5
TOTAL EXPENSES	16,156.8	13,380.7	11,930.8
OPERATING INCOME	3,482.7	3,411.3	2,987.7
Other Income (Expense):			
Other Income	11.6	41.4	57.0
Allowance for Equity Funds Used During Construction	133.7	139.7	148.1
Non-Service Cost Components of Net Periodic Benefit Cost	188.5	118.6	119.0
Interest Expense	(1,396.1)	(1,199.1)	(1,165.7)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	2,420.4	2,511.9	2,146.1
Income Tax Expense	5.4	115.5	40.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(109.4)	91.7	91.1
NET INCOME	2,305.6	2,488.1	2,196.7
Net Income (Loss) Attributable to Noncontrolling Interests	(1.6)	—	(3.4)
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2,307.2	$ 2,488.1	$ 2,200.1
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	511,841,946	500,522,177	495,718,223
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.51	$ 4.97	$ 4.44
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	513,484,609	501,784,032	497,226,867
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.49	$ 4.96	$ 4.42

See Notes to Financial Statements of Registrants beginning on page 81.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2022, 2021 and 2020
(in millions)

	Years Ended December 31,		
	2022	**2021**	**2020**
Net Income	$ 2,305.6	$ 2,488.1	$ 2,196.7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $21.6, $66.6 and $1.8 in 2022, 2021 and 2020, Respectively	81.4	250.5	6.9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(2.8), $(2.2) and $(1.9) in 2022, 2021 and 2020, Respectively	(10.4)	(8.1)	(7.0)
Pension and OPEB Funded Status, Net of Tax of $(41.3), $7.3 and $16.7 in 2022, 2021 and 2020, Respectively	(155.4)	27.5	62.7
Reclassifications of KPCo Pension and OPEB Regulatory Assets, Net of Tax of $(4.4), $0 and $0 in 2022, 2021 and 2020, Respectively	(16.7)	—	—
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(101.1)	269.9	62.6
TOTAL COMPREHENSIVE INCOME	2,204.5	2,758.0	2,259.3
Total Comprehensive Loss Attributable To Noncontrolling Interests	(1.6)	—	(3.4)
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2,206.1	$ 2,758.0	$ 2,262.7

See Notes to Financial Statements of Registrants beginning on page 81.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2022, 2021 and 2020
(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, 2019	514.4	$ 3,343.4	$ 6,535.6	$ 9,900.9	$ (147.7)	$ 281.0	$ 19,913.2
Issuance of Common Stock	2.4	15.9	139.1				155.0
Common Stock Dividends				(1,415.0) (a)		(9.9)	(1,424.9)
Other Changes in Equity			(85.8) (b)			(0.4)	(86.2)
ASU 2016-13 Adoption				1.8			1.8
Acquisition of Incremental Interest in Santa Rita East						(43.7)	(43.7)
Net Income (Loss)				2,200.1		(3.4)	2,196.7
Other Comprehensive Income					62.6		62.6
TOTAL EQUITY – DECEMBER 31, 2020	516.8	3,359.3	6,588.9	10,687.8	(85.1)	223.6	20,774.5
Issuance of Common Stock	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

(a) Cash dividends declared per AEP common share were $3.17, $3.00 and $2.84 for the years ended December 31, 2022, 2021 and 2020, respectively.
(b) Includes $(121) million related to a forward equity purchase contract associated with the issuance of Equity Units. See "Equity Units" section of Note 14 for additional information.

See Notes to Financial Statements of Registrants beginning on page 81.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2022 and 2021
(in millions)

	December 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 509.4	$ 403.4
Restricted Cash (December 31, 2022 and 2021 Amounts Include $47.1 and $48, Respectively, Related to Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	47.1	48.0
Other Temporary Investments (December 31, 2022 and 2021 Amounts Include $182.9 and $214.8, Respectively, Related to EIS and Transource Energy)	187.5	220.4
Accounts Receivable:		
Customers	1,081.5	720.9
Accrued Unbilled Revenues	287.9	204.4
Pledged Accounts Receivable – AEP Credit	1,207.4	1,038.0
Miscellaneous	49.6	33.9
Allowance for Uncollectible Accounts	(56.1)	(55.6)
Total Accounts Receivable	2,570.3	1,941.6
Fuel	413.2	307.9
Materials and Supplies	888.9	681.3
Risk Management Assets	340.4	194.4
Accrued Tax Benefits	99.4	121.5
Regulatory Asset for Under-Recovered Fuel Costs	1,286.8	647.8
Margin Deposits	81.9	193.4
Assets Held for Sale	2,823.5	2,919.7
Prepayments and Other Current Assets	170.3	129.8
TOTAL CURRENT ASSETS	9,418.7	7,809.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,597.7	23,088.1
Transmission	32,312.9	29,911.1
Distribution	26,077.2	24,440.0
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	6,142.1	5,682.9
Construction Work in Progress	4,664.1	3,684.3
Total Property, Plant and Equipment	93,794.0	86,806.4
Accumulated Depreciation and Amortization	22,511.1	20,805.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	71,282.9	66,001.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,281.2	4,142.3
Securitized Assets	446.0	552.8
Spent Nuclear Fuel and Decommissioning Trusts	3,341.2	3,867.0
Goodwill	52.5	52.5
Long-term Risk Management Assets	284.1	267.0
Operating Lease Assets	645.0	578.3
Deferred Charges and Other Noncurrent Assets	3,717.8	4,398.3
TOTAL OTHER NONCURRENT ASSETS	12,767.8	13,858.2
TOTAL ASSETS	$ 93,469.4	$ 87,668.7

See Notes to Financial Statements of Registrants beginning on page 81.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2022 and 2021
(dollars in millions)

	December 31, 2022	December 31, 2021
CURRENT LIABILITIES		
Accounts Payable	$ 2,613.0	$ 2,054.6
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	750.0
Other Short-term Debt	3,362.2	1,864.0
Total Short-term Debt	4,112.2	2,614.0
Long-term Debt Due Within One Year (December 31, 2022 and 2021 Amounts Include $218.2 and $190.5, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)	1,996.4	2,153.8
Risk Management Liabilities	145.2	75.4
Customer Deposits	370.0	321.6
Accrued Taxes	1,672.8	1,586.4
Accrued Interest	327.6	273.2
Obligations Under Operating Leases	113.4	97.6
Liabilities Held for Sale	1,955.7	1,880.9
Other Current Liabilities	1,261.1	1,369.2
TOTAL CURRENT LIABILITIES	14,567.4	12,426.7
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2022 and 2021 Amounts Include $755.3 and $840.5, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)	33,626.2	31,300.7
Long-term Risk Management Liabilities	345.3	230.3
Deferred Income Taxes	8,493.3	8,202.5
Regulatory Liabilities and Deferred Investment Tax Credits	7,999.6	8,686.3
Asset Retirement Obligations	2,860.8	2,676.2
Employee Benefits and Pension Obligations	257.3	328.4
Obligations Under Operating Leases	552.1	492.8
Deferred Credits and Other Noncurrent Liabilities	599.1	601.3
TOTAL NONCURRENT LIABILITIES	54,733.7	52,518.5
TOTAL LIABILITIES	69,301.1	64,945.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Contingently Redeemable Performance Share Awards	45.9	43.3
TOTAL MEZZANINE EQUITY	45.9	43.3
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2022	2021
Shares Authorized	600,000,000	600,000,000
Shares Issued	525,099,321	524,416,175

	December 31, 2022	December 31, 2021
(11,233,240 and 20,204,160 Shares were Held in Treasury as of December 31, 2022 and 2021, Respectively)	3,413.1	3,408.7
Paid-in Capital	8,051.0	7,172.6
Retained Earnings	12,345.6	11,667.1
Accumulated Other Comprehensive Income (Loss)	83.7	184.8
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	23,893.4	22,433.2
Noncontrolling Interests	229.0	247.0
TOTAL EQUITY	24,122.4	22,680.2
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 93,469.4	$ 87,668.7

See Notes to Financial Statements of Registrants beginning on page 81.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2022, 2021 and 2020
(in millions)

	Years Ended December 31,		
	2022	2021	2020
OPERATING ACTIVITIES			
Net Income	$ 2,305.6	$ 2,488.1	$ 2,196.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	3,202.8	2,825.7	2,682.8
Rockport Plant, Unit 2 Lease Amortization	—	135.4	136.5
Deferred Income Taxes	(137.2)	107.6	196.1
Loss on the Expected Sale of the Kentucky Operations	363.3	—	—
Asset Impairments and Other Related Charges	48.8	11.6	—
Impairment of Equity Method Investment	188.0	—	—
Allowance for Equity Funds Used During Construction	(133.7)	(139.7)	(148.1)
Mark-to-Market of Risk Management Contracts	15.5	112.3	66.5
Amortization of Nuclear Fuel	82.9	85.3	87.5
Pension Contributions to Qualified Plan Trust	—	—	(110.3)
Property Taxes	(41.2)	(68.0)	(43.3)
Deferred Fuel Over/Under-Recovery, Net	(319.2)	(1,647.9)	(31.8)
Gain on Sale of Mineral Rights	(116.3)	—	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	—
Change in Regulatory Assets	(46.7)	(238.9)	(337.9)
Change in Other Noncurrent Assets	(187.7)	(126.6)	(151.0)
Change in Other Noncurrent Liabilities	337.8	206.4	(54.5)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(681.7)	(119.7)	(129.3)
Fuel, Materials and Supplies	(313.9)	300.2	(142.9)
Accounts Payable	489.2	200.6	(35.3)
Accrued Taxes, Net	105.4	218.7	20.1
Rockport Plant, Unit 2 Operating Lease Payments	—	(147.7)	(147.7)
Other Current Assets	109.0	(151.3)	34.3
Other Current Liabilities	54.3	(212.2)	(255.5)
Net Cash Flows from Operating Activities	5,288.0	3,839.9	3,832.9
INVESTING ACTIVITIES			
Construction Expenditures	(6,671.7)	(5,659.6)	(6,246.3)
Purchases of Investment Securities	(2,784.2)	(1,955.1)	(1,678.8)
Sales of Investment Securities	2,743.8	1,901.4	1,644.3
Acquisitions of Nuclear Fuel	(100.7)	(104.5)	(69.7)
Acquisition of the Dry Lake Solar Project	—	(114.4)	—
Acquisition of the North Central Wind Energy Facilities	(1,207.3)	(652.8)	—
Proceeds from Sales of Assets	218.0	118.9	71.1
Other Investing Activities	50.3	32.2	45.5
Net Cash Flows Used for Investing Activities	(7,751.8)	(6,433.9)	(6,233.9)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	826.5	600.5	155.0
Issuance of Long-term Debt	4,649.7	6,486.3	5,626.1
Issuance of Short-term Debt with Original Maturities greater than 90 Days	833.9	1,393.3	1,396.5
Change in Short-term Debt with Original Maturities less than 90 Day, Net	1,650.4	(487.3)	(448.4)
Retirement of Long-term Debt	(2,345.4)	(2,989.3)	(1,339.8)
Redemption of Short-term Debt with Original Maturities greater than 90 Days	(986.1)	(771.3)	(1,307.1)
Principal Payments for Finance Lease Obligations	(309.5)	(64.0)	(61.7)
Dividends Paid on Common Stock	(1,645.2)	(1,519.5)	(1,424.9)
Redemption of Noncontrolling Interests	—	—	(100.2)
Other Financing Activities	(105.4)	(41.6)	(88.8)
Net Cash Flows from Financing Activities	2,568.9	2,607.1	2,406.7
Net Increase in Cash, Cash Equivalents and Restricted Cash	105.1	13.1	5.7
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	451.4	438.3	432.6
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 556.5	$ 451.4	$ 438.3

See Notes to Financial Statements of Registrants beginning on page 81.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

ORGANIZATION

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

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

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

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. In addition, these nonregulated subsidiaries control certain wind assets, the power from which is marketed and sold in ERCOT.

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

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

In addition, the FERC regulates the SIA, Operating Agreement, 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 (consolidated VIEs) and Restoration Funding (a consolidated VIE). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a consolidated VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (consolidated VIEs). The consolidated financial statements for 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. In October 2020, AEP Texas, PSO and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated third-party related to the Oklaunion Power Station site. See "Oklaunion Power Station" section of Note 7 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.

AEP System Tax Allocation

AEP and subsidiaries join in the filing of a consolidated federal income tax return. Historically, the allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocated the benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries through a reduction of current tax expense. In the first quarter of 2022, AEP and subsidiaries changed accounting for the Parent Company Loss Benefit from a reduction of current tax expense to an allocation through equity. The impact of this change was immaterial to the Registrant Subsidiaries' financial statements. 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.

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, 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

	December 31, 2021		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 403.4	$ 0.1	$ 2.5
Restricted Cash	48.0	30.4	17.6
Total Cash, Cash Equivalents and Restricted Cash	$ 451.4	$ 30.5	$ 20.1

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

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, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 14 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. The assessment is performed separately by each participating AEP subsidiary, which inherently contemplates any differences in geographical risk characteristics for the allowance. KPCo terminated selling accounts receivable to AEP Credit in the first quarter of 2022, based on the pending sale to Liberty. As a result of the termination, 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. For receivables related to KPCo and APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded 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 transactions with REPs which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Reliant Energy, Direct Energy and TXU Energy (a)	**2022**	**2021**	**2020**
Percentage of Total Revenues	45 %	43 %	46 %
Percentage of Accounts Receivable – Customers	42 %	41 %	40 %

(a) In January 2021, NRG Energy, parent company of Reliant Energy, completed a deal to purchase Direct Energy from Centrica.

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	**2022**	**2021**	**2020**
Percentage of Total Revenues	79 %	79 %	78 %
Percentage of Total Accounts Receivable	72 %	81 %	78 %

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 not 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 for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

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

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

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

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

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

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. 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.

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.

Excise Taxes (Applies to all Registrants except AEPTCo)

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

Debt

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

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

Goodwill (Applies to AEP)

When the Registrants acquire a business, as defined by the accounting guidance for "Business Combinations," management recognizes all acquired assets and liabilities at their fair value. To the extent that consideration exceeds the net fair value of the identified assets and liabilities, goodwill is recognized on the balance sheets. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at its estimated fair value. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods.

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

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

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

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

Benefit Plans

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

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

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

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

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

OPEB Plans Assets	Target
Equity	59 %
Fixed Income	40 %
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, 2022 and 2021, the fair value of securities on loan as part of the program was $83 million and $137 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2022 and 2021.

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 all Registrants except AEPTCo and OPCo)

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, 2022, 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. All performance units awarded prior to 2017 and restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vested to executive officers were settled in cash. During 2019, all of the remaining performance units and restricted stock units that settle in cash were settled. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and 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. These stock units were payable in cash to directors after their service ends. Effective in June 2022, these stock units became payable in AEP common stock rather than cash.

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, 2022, 2021 and 2020 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, 2022, 2021 and 2020, compensation costs are included in Net Income for the performance shares, career shares, restricted stock units and the non-employee director stock units. 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.

AEP's significant equity method investments include ETT, DHLC and four joint venture interests which own distinct wind generation facilities. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Years Ended December 31,					
	2022		2021		2020	
	(in millions, except per-share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$2,307.2		$2,488.1		$2,200.1	
Weighted-Average Number of Basic AEP Common Shares Outstanding	511.8	$ 4.51	500.5	$ 4.97	495.7	$ 4.44
Weighted-Average Dilutive Effect of Stock-Based Awards	1.7	(0.02)	1.3	(0.01)	1.5	(0.02)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	513.5	$ 4.49	501.8	$ 4.96	497.2	$ 4.42

Equity Units are potentially dilutive securities but were excluded from the calculation of diluted EPS for the years ended December 31, 2022, 2021 and 2020, as the dilutive stock price thresholds were not met. See Note 14 - Financing Activities for additional information related to Equity Units.

There were no antidilutive shares outstanding as of December 31, 2022 and 2021. There were 128 thousand antidilutive shares outstanding as of December 31, 2020.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2022, 2021 and 2020:

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

2020

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,487.5	$ 364.2	$ 249.0	$ 507.8	$ 393.3	$ 275.0	$ 171.9	$ 271.2
Amortization of Certain Securitized Assets	171.3	171.3	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	24.0	(5.7)	—	(0.3)	18.3	1.6	1.6	1.5
Total Depreciation and Amortization	$ 2,682.8	$ 529.8	$ 249.0	$ 507.5	$ 411.6	$ 276.6	$ 173.5	$ 272.7

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	2022	2021	2020
	Years Ended December 31, (in millions)		
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 1,286.3	$ 1,137.2	$ 1,029.1
Income Taxes	116.8	13.2	(49.1)
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	31.8	287.6	44.2
Construction Expenditures Included in Current Liabilities as of December 31,	1,258.9	1,180.4	975.4
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	—	5.5
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	—	—	33.4
Noncash Contribution of Assets to Cedar Creek Project	—	(9.3)	—
Noncontrolling Interest Assumed - Dry Lake Solar Project	—	35.3	—
Forward Equity Purchase Contracts Included in Current and Noncurrent Liabilities as of December 31,	—	—	110.6

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. There are no new standards expected to have a material impact on the Registrants' financial statements.

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2022, 2021 and 2020. 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.

AEP

	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	(a)	—	(155.4)	340.3
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	0.1	—		—	—	0.1
Purchased Electricity for Resale (b)	(528.6)	—		—	—	(528.6)
Interest Expense (b)	—	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	—	—		—	(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: Commodity	Cash Flow Hedges: Interest Rate		Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
				(in millions)		
Balance in AOCI as of December 31, 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	(a)	—	27.5	536.8
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	0.7	—		—	—	0.7
Purchased Electricity for Resale (b)	(334.8)	—		—	—	(334.8)
Interest Expense (b)	—	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

For the Year Ended December 31, 2020	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate		Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
				(in millions)		
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)		$ 130.7	$ (163.4)	$ (147.7)
Change in Fair Value Recognized in AOCI, Net of Tax	(89.2)	(39.9)	(a)	—	62.7	(66.4)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(0.4)	—		—	—	(0.4)
Purchased Electricity for Resale (b)	167.6	—		—	—	167.6
Interest Expense (b)	—	4.9		—	—	4.9
Amortization of Prior Service Cost (Credit)	—	—		(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—		10.3	—	10.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	167.2	4.9		(8.9)	—	163.2
Income Tax (Expense) Benefit	35.1	1.0		(1.9)	—	34.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	132.1	3.9		(7.0)	—	129.0
Net Current Period Other Comprehensive Income (Loss)	42.9	(36.0)		(7.0)	62.7	62.6
Balance in AOCI as of December 31, 2020	$ (60.6)	$ (47.5)		$ 123.7	$ (100.7)	$ (85.1)

AEP Texas

For the Year Ended December 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2021	$ (1.3)	$ 5.3	$ (10.5)	$ (6.5)
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	(3.2)	(3.2)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.2	—	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.1	—	1.4
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.1	—	1.1
Net Current Period Other Comprehensive Income (Loss)	1.0	0.1	(3.2)	(2.1)
Balance in AOCI as of December 31, 2022	$ (0.3)	$ 5.4	$ (13.7)	$ (8.6)

For the Year Ended December 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2020	$ (2.3)	$ 5.1	$ (11.7)	$ (8.9)
Change in Fair Value Recognized in AOCI, Net of Tax	0.1	—	1.2	1.3
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.2	—	—	1.2
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.2	0.2	—	1.4
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.9	0.2	—	1.1
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	1.2	2.4
Balance in AOCI as of December 31, 2021	$ (1.3)	$ 5.3	$ (10.5)	$ (6.5)

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (3.4)	$ 4.9	$ (14.3)	$ (12.8)
Change in Fair Value Recognized in AOCI, Net of Tax	0.1	—	2.6	2.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.1	0.2	2.6	3.9
Balance in AOCI as of December 31, 2020	$ (2.3)	$ 5.1	$ (11.7)	$ (8.9)

For the Year Ended December 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2021	$ 7.5	$ 1.2	$ 15.7	$ 24.4
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	(24.1)	(24.1)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.0)	—	—	(1.0)
Amortization of Prior Service Cost (Credit)	—	(5.4)	—	(5.4)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.0)	(5.4)	—	(6.4)
Income Tax (Expense) Benefit	(0.2)	(1.1)	—	(1.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)	(4.3)	—	(5.1)
Net Current Period Other Comprehensive Income (Loss)	(0.8)	(4.3)	(24.1)	(29.2)
Balance in AOCI as of December 31, 2022	$ 6.7	$ (3.1)	$ (8.4)	$ (4.8)

For the Year Ended December 31, 2021	Cash Flow Hedges - Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2020	$ (0.8)	$ 5.4	$ 2.6	$ 7.2
Change in Fair Value Recognized in AOCI, Net of Tax	9.2	—	13.1	22.3
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(5.3)	—	(6.4)
Income Tax (Expense) Benefit	(0.2)	(1.1)	—	(1.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.9)	(4.2)	—	(5.1)
Net Current Period Other Comprehensive Income (Loss)	8.3	(4.2)	13.1	17.2
Balance in AOCI as of December 31, 2021	$ 7.5	$ 1.2	$ 15.7	$ 24.4

For the Year Ended December 31, 2020	Cash Flow Hedges - Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ 0.9	$ 9.2	$ (5.1)	$ 5.0
Change in Fair Value Recognized in AOCI, Net of Tax	(0.7)	—	7.7	7.0
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.3)	—	—	(1.3)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)	(4.8)	—	(6.1)
Income Tax (Expense) Benefit	(0.3)	(1.0)	—	(1.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)	(3.8)	—	(4.8)
Net Current Period Other Comprehensive Income (Loss)	(1.7)	(3.8)	7.7	2.2
Balance in AOCI as of December 31, 2020	$ (0.8)	$ 5.4	$ 2.6	$ 7.2

For the Year Ended December 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2021	$ (6.7)	$ 4.7	$ 0.7	$ (1.3)
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	(0.3)	(0.3)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.4)	—	1.6
Income Tax (Expense) Benefit	0.4	(0.1)	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.3)	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.3)	(0.3)	1.0
Balance in AOCI as of December 31, 2022	$ (5.1)	$ 4.4	$ 0.4	$ (0.3)

For the Year Ended December 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2020	$ (8.3)	$ 4.8	$ (3.5)	$ (7.0)
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	4.2	4.2
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.1)	—	1.9
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.1)	—	1.5
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.1)	4.2	5.7
Balance in AOCI as of December 31, 2021	$ (6.7)	$ 4.7	$ 0.7	$ (1.3)

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (9.9)	$ 4.9	$ (6.6)	$ (11.6)
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	3.1	3.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.1)	—	1.9
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.1)	—	1.5
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.1)	3.1	4.6
Balance in AOCI as of December 31, 2020	$ (8.3)	$ 4.8	$ (3.5)	$ (7.0)

For the Year Ended December 31, 2022	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2021	$ —
Change in Fair Value Recognized in AOCI, Net of Tax	1.3
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	1.3
Balance in AOCI as of December 31, 2022	$ 1.3

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

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2019	$ 1.1
Change in Fair Value Recognized in AOCI, Net of Tax	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
Balance in AOCI as of December 31, 2020	$ 0.1

SWEPCo

For the Year Ended December 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2021	$ 1.2	$ (4.4)	$ 9.9	$ 6.7
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	(9.2)	(9.2)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(0.1)	—	—	(0.1)
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.1)	(2.0)	—	(2.1)
Income Tax (Expense) Benefit	—	(0.4)	—	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.1)	(1.6)	—	(1.7)
Net Current Period Other Comprehensive Income (Loss)	(0.1)	(1.6)	(9.2)	(10.9)
Balance in AOCI as of December 31, 2022	$ 1.1	$ (6.0)	$ 0.7	$ (4.2)

For the Year Ended December 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2020	$ (0.3)	$ (2.8)	$ 5.0	$ 1.9
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	4.9	4.9
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(2.0)	—	(0.1)
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.6)	—	(0.1)
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.6)	4.9	4.8
Balance in AOCI as of December 31, 2021	$ 1.2	$ (4.4)	$ 9.9	$ 6.7

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (1.8)	$ (1.3)	$ 1.8	$ (1.3)
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	3.2	3.2
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.1	—	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(1.9)	—	—
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.5)	—	—
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.5)	3.2	3.2
Balance in AOCI as of December 31, 2020	$ (0.3)	$ (2.8)	$ 5.0	$ 1.9

(a) The change in fair value includes $(10) million, $(7) million and $6 million for the years ended December 31, 2022, 2021 and 2020, respectively, related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC.
(b) Amounts reclassified to the referenced line item on the statements of income.

4. RATE MATTERS

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

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, 2022, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is approximately $614 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)

2017-2019 Virginia Triennial Review

In November 2020, the Virginia SCC issued an order on APCo's 2017-2019 Triennial Review filing concluding that APCo earned above its authorized ROE but within its ROE band for the 2017-2019 period, resulting in no refund to customers and no change to APCo base rates on a prospective basis. The Virginia SCC approved a prospective 9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a statutory 140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top). APCo appealed this order and a similar order on reconsideration to the Virginia Supreme Court in March 2021, alleging the Virginia SCC erred in finding that costs associated with asset impairments related to APCo early retirement determinations for certain generation facilities should not be attributed to the 2017-2019 test periods under review and deemed fully recovered in the period recorded. In August 2022, the Virginia Supreme Court agreed with this portion of APCo's appeal and remanded this issue regarding the retired coal-fired plants back to the Virginia SCC for further proceedings. In September 2022, as a result of the Virginia Supreme Court ruling, APCo expensed the remaining $25 million closed coal plant regulatory asset that was previously ordered by the Virginia SCC and recorded a $37 million regulatory asset for previously incurred costs that APCo is expecting to recover as a result of earning below its 2017-2019 authorized ROE band.

In response to the Virginia Supreme Court's August 2022 opinion, the Virginia SCC initiated remand proceedings and, in December 2022, issued an order that: (a) approved APCo's requested $37 million regulatory asset related to previously incurred costs as a result of APCo earning below its 2017-2019 authorized ROE band, (b) authorized a $28 million annual increase in APCo Virginia base rates effective October 2022 and (c) approved a rider to recover approximately $48 million related to this APCo Virginia base rate increase for the period January 2021 through September 2022. APCo's 2022 financial statements reflect the impact of the Virginia SCC's December 2022 order.

2020-2022 Virginia Triennial Review

In March 2023, APCo will submit its required Virginia earnings test calculation to the Virginia SCC for the 2020-2022 Triennial Review 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 major storms, the early retirement of fossil fuel generating assets and certain projects necessary to comply with state and federal environmental legislation. As of December 31, 2022, APCo has deferred approximately $38 million related to previously incurred costs as a result of the current estimate that APCo will earn below the bottom of its authorized ROE band during the 2020-2022 Triennial Review period. If it is determined that APCo has earned above the bottom of its authorized ROE band for the 2020-2022 Triennial Review period it could reduce future net income and cash flows and impact financial condition.

CCR/ELG Compliance Plan Filings

In December 2020, APCo submitted filings with the Virginia SCC and WVPSC requesting approvals necessary to implement CCR/ELG compliance plans at the Amos and Mountaineer Plants. In August 2021, the Virginia SCC issued an order approving recovery of CCR-related operation and maintenance expenses and investments at the Amos and Mountaineer Plants through an active rider. The order also denied APCo's request to recover the cost of ELG investments and denied recovery of previously incurred ELG costs, but did not preclude APCo from refiling for approval. Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approved recovery of the West Virginia jurisdictional share of these costs through an active rider.

In March 2022, APCo refiled for approval to recover the Virginia jurisdictional share of ELG investments at the Amos and Mountaineer Plants. The Virginia SCC issued a November 2022 order approving this request.

2021 and 2022 ENEC (Expanded Net Energy Cost) Filings

In April 2021, APCo and WPCo (the Companies) requested a $73 million annual increase in ENEC rates based on a cumulative combined $55 million ENEC under-recovery as of February 28, 2021 and a combined $18 million increase in projected ENEC costs for the period September 2021 through August 2022. In September 2021, the WVPSC issued an order approving a $7 million overall increase in ENEC rates, including an approval for recovery of the Companies' cumulative $55 million ENEC under-recovery balance and a $48 million reduction in projected costs for the period September 2021 through August 2022. Subsequently, the Companies submitted a request for reconsideration of this order, identifying flaws in the WVPSC's calculation of forecasted future year fuel expense and purchased power costs.

In March 2022, the WVPSC issued an order granting the Companies' request for reconsideration, in part, and approving $31 million in projected costs for the period September 2021 through August 2022. The order also reopened the 2021 ENEC case to require the Companies to explain the significant growth in the reported under-recovery of ENEC costs and to provide various other information including revised projected costs for the period March 2022 through August 2022. Also, in March 2022, the Companies filed testimony providing the information requested in the WVPSC's order and requested a $155 million annual increase in ENEC rates effective May 1, 2022. In May 2022, the WVPSC issued an order approving a $93 million overall increase to ENEC rates to recover projected annual ENEC costs. However, the WVPSC stated that actual and projected ENEC costs are still subject to a prudency review.

In April 2022, the Companies submitted their 2022 annual ENEC filing with the WVPSC requesting a $297 million annual increase in ENEC revenues, inclusive of the previously requested $155 million increase, effective September 1, 2022.

In September 2022, following an agreed upon delay in the proceedings of the Companies' 2022 ENEC case, certain intervenors submitted testimony recommending disallowances of at least $83 million to the Companies' historical period ENEC under-recovery balance along with proposals to either securitize the Companies' remaining ENEC balance or defer recovery of this balance beyond the traditional one-year period. West Virginia Staff recommended a $13 million increase in ENEC rates pending the outcome of the ENEC prudency review. In February 2023, the WVPSC issued an order stating that the commission will not grant additional rate increases for fuel costs until the WVPSC staff completes its prudency review. As of December 31, 2022, the Companies' cumulative ENEC under-recovery was $520 million. If any deferred ENEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

June 2022 West Virginia Storm Costs

In June 2022, the West Virginia service territories of APCo and WPCo (the Companies) were impacted by strong winds from multiple storms resulting in system damages and power outages. As of December 31, 2022, the Companies incurred and deferred an estimated $17 million in incremental distribution operation and maintenance expenses related to service restoration efforts. The Companies will seek recovery of these deferrals in future filings. If any of the storm restoration costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through December 31, 2022, AEP's share of ETT's cumulative revenues that are subject to review is approximately $1.5 billion. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In December 2022, ETT and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement maintains ETT's previously allowed ROE and capital structure and includes: (a) a $14 million decrease to the current annual revenue requirement effective February 1, 2023, (b) a provision that ETT must make an interim transmission cost of service filing by June 1, 2023, (c) a $2 million line item decrease to the revenue requirement determined in each interim transmission cost of service filing until the filing of the next comprehensive base rate review and (d) no determination of prudence on any transmission investment added since ETT's last comprehensive base rate review, which would leave the $1.5 billion of cumulative revenues above subject to review in the next comprehensive base rate review. In February 2023, the PUCT approved the stipulation and settlement agreement. As part of the approved agreement, new rates will be implemented in February 2023 and ETT is required to file for a comprehensive base rate review no later than February 1, 2025.

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

Michigan Power Supply Cost Recovery (PSCR) Reconciliation

In April 2022, an ALJ issued a PFD for I&M's PSCR reconciliation for the 12-month period ending December 31, 2020, recommending the MPSC disallow approximately $8 million of purchased power costs that I&M incurred under the Inter-Company Power Agreement with OVEC and the Unit Power Agreement with AEGCo. In February 2023, the MPSC issued an order resulting in a $1 million disallowance of 2020 OVEC costs.

Indiana Earnings Test Filings

I&M is required by Indiana law to submit an earnings test evaluation for the most recent one-year and five-year periods as part of I&M's semi-annual Indiana FAC filings. These earnings test evaluations require I&M to include a credit in the FAC factor computation for periods in which I&M earned above its authorized return for both the one-year and five-year periods. The credit is determined as 50% of the lower of the one-year or five-year earnings above the authorized level. In August 2022, I&M submitted its FAC filing and earnings test evaluation for the period ended May 2022, which calculated a credit due to customers of $14 million. In October 2022, the IURC approved the FAC filing and earnings test evaluation, with the credit to customers starting in November 2022 through the FAC. As of December 31, 2022, I&M's financial statements adequately reflect the estimated impact of I&M's upcoming Indiana earnings test filings. If it is determined that I&M's over-earnings exceed what has been recorded, it could reduce future net income and cash flows and impact financial condition.

2022 Michigan Integrated Resource Plan (IRP) Filing

In February 2022, I&M filed a request with the MPSC for approval of its 2022 IRP. Included in that filing were requests for approval and deferral of costs associated with resources commencing construction within three years of the Commission's order in the filing. These resources include the new generation resources expected to be in-service by 2028 and demand-side resources, including load management programs and conservation voltage reduction investments. I&M is also requesting MPSC approval of I&M's Rockport Plant, Unit 2 transition plan consistent with that approved by the IURC, including certain cost recovery related to remaining net book value of leasehold improvements made during the term of the Rockport Unit 2 lease and future use of Rockport Plant, Unit 2 as a capacity resource. In addition, I&M has made requests for approval of a financial incentive on certain power purchase agreements and load management programs. As of December 31, 2022, I&M's total net book value for these Rockport Plant, Unit 2 leasehold improvements was approximately $17 million on a Michigan jurisdictional basis.

In November 2022, I&M filed a settlement agreement, which included a Rockport Plant, Unit 2 transition plan. Under this plan, I&M Michigan ratepayers will receive a jurisdictional share of post-lease revenues in excess of costs from Rockport Plant, Unit 2's operations as a merchant facility. In addition, I&M will continue to recover the remaining net book value of Rockport Plant, Unit 2 leasehold improvements through 2028, including a pretax return. In February 2023, the MPSC issued an order approving the settlement agreement without modification.

KPCo Rate Matters (Applies to AEP)

CCR/ELG Compliance Plan Filings

KPCo and WPCo each own a 50% interest in the Mitchell Plant. As of December 31, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $577 million. In December 2020 and February 2021, WPCo and KPCo filed requests with the WVPSC and KPSC, respectively, to obtain the regulatory approvals necessary to implement CCR and ELG compliance plans and seek recovery of the estimated $132 million investment for the Mitchell Plant that would allow the plant to continue operating beyond 2028. Within those requests, WPCo and KPCo also filed a $25 million alternative to implement only the CCR-related investments with the WVPSC and KPSC, respectively, which would allow the Mitchell Plant to continue operating only through 2028.

In July 2021, the KPSC issued an order approving the CCR only alternative and rejecting the full CCR and ELG compliance plan. In May 2022, the KPSC approved recovery of the Kentucky jurisdictional share of ELG costs incurred at the Mitchell Plant prior to July 15, 2021.

In August 2021, the WVPSC approved the full CCR and ELG compliance plan for the WPCo share of the Mitchell Plant. In September 2021, WPCo submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021. Due to the rejection by the KPSC of the KPCo share of the ELG investments, WPCo requested the WVPSC consider approving the construction and recovery of all ELG costs at the plant. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed WPCo to proceed with CCR/ELG compliance plans that would allow the plant to continue operating beyond 2028. The WVPSC also ordered that WPCo will be given the opportunity to recover, from its customers, the ELG and new capital and operating costs arising solely from the WVPSC's directive to operate the plant beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. The WVPSC's order further states that unless KPCo pays for its share of costs for ELG improvements and costs necessary to continue operations beyond 2028, the benefit of the capacity and energy made possible by those improvements and operating Mitchell Plant beyond 2028 should benefit only West Virginia jurisdictional customers who have shared in paying for those costs.

<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. Management disagrees with these claims and is unable to predict the impact of these disputes; however, if any costs are disallowed or refunds are ordered it could reduce future net income and cash flows and impact financial condition. See "OVEC" section of Note 17 for additional information on AEP and OPCo's investment in OVEC.

June 2022 Storm Costs

In June 2022, the service territory of OPCo was impacted by strong winds from multiple storms resulting in power outages and damage to the transmission and distribution infrastructures. As of December 31, 2022, OPCo had incurred approximately $20 million in incremental operation and maintenance costs related to service restoration efforts. The incremental storm restoration costs have been deferred as regulatory assets and OPCo is expected to seek recovery in a future filing. In July 2022, intervenors filed a motion requesting the PUCO open a formal investigation into the power outages that occurred as a result of the June storms and determine if OPCo was negligent and liable to consumers for damages incurred as a result of the power outages. Separately, in July 2022, the PUCO directed its staff to conduct an after-action review to examine the circumstances of the event and OPCo's response to determine if OPCo adhered to the laws and rules in the state, followed its PUCO-approved emergency plan and responded appropriately to the event in an effort to mitigate the negative effects. In January 2023, the PUCO Staff issued a report which concluded OPCo was required to proactively shut down parts of its distribution system in order to avoid damages to the system and further outages and that OPCo adhered to its emergency plan. The report also directed OPCo to revise its vegetation programs around high voltage transmission lines and recommended that it make improvements to its emergency communications procedures. If any of the storm restoration costs are not recoverable, 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. 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.

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

2022 Oklahoma Base Rate Case

In November 2022, PSO filed a request with the OCC for a $173 million annual increase in rates based upon a 10.4% ROE with a capital structure of 45.4% debt and 54.6% common equity, net of existing rider revenues and certain incremental renewable facility benefits expected to be provided to customers through riders. The requested annual revenue increase includes 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 includes recovery of the 154 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 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. PSO expects to close on the acquisition and place the Rock Falls Wind Facility in-service during the first quarter of 2023. OCC approval is not a condition precedent to closing on the acquisition of the Rock Falls Wind Facility. In addition, PSO requested an annual formula based rate tariff, with an initial one-year pilot term. In the event the requested formula based rate tariff is denied, PSO has requested an expanded rider to recover certain distribution investments and related expenses as well as an expanded transmission cost recovery rider. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, severe winter weather had a significant impact in SPP, resulting in the declaration of Energy Emergency Alert Levels 2 and 3 for the first time in SPP's history. The winter storm increased the demand for natural gas and restricted the available natural gas supply resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system.

In April 2021, the OCC approved a waiver for PSO allowing the deferral of the extraordinary fuel and purchases of electricity as regulatory assets, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. Also in April 2021, legislation was enacted in Oklahoma permitting securitized financing of qualified costs from extreme weather events. This legislation provides certain authority to the OCC to approve amounts to be recovered from the issuance of ratepayer-backed securitized bonds issued by the ODFA, an Oklahoma governmental agency. In January 2022, PSO, OCC staff and certain intervenors filed a joint stipulation and settlement agreement with the OCC to approve the securitization of PSO's extraordinary fuel costs and purchases of electricity. In February 2022, the OCC approved the joint stipulation and settlement agreement which included a determination that all of PSO's extraordinary fuel costs and purchases of electricity were prudent and reasonable and also provided a 0.75% carrying charge related to those costs, subject to true-up based on actual financing costs.

In September 2022, PSO received proceeds of $687 million from the ODFA which issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event, which were previously recorded as Regulatory Assets on PSO's balance sheet. The securitization bonds are the obligation of the ODFA and there is no recourse against PSO in the event of a bond default, and therefore are not recorded as Long-term Debt on PSO's balance sheet. PSO will serve as the servicing agent of the bonds and is responsible for the routine billing and collection of the securitization charges and remitting those collections back to the ODFA. The securitization charges billed to and collected from customers are not included as revenue on PSO's statement of income. The collections from customers will occur over 20 years.

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

2012 Texas Base Rate Case

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

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

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant. In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. No parties filed a motion for rehearing with the Texas Supreme Court. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court 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. SWEPCo disagrees with the Court of Appeals decision. SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court in November 2021. 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. The Texas Supreme Court requested comments on rehearing by March 1, 2023. If SWEPCo's request for rehearing is denied, the case will be remanded to the PUCT for future proceedings.

Management does not believe a disallowance of capitalized Turk Plant costs or a revenue refund is probable as of December 31, 2022. However, if SWEPCo is ultimately unable to recover AFUDC in excess of the Texas jurisdictional capital cost cap, it would be expected to result in a pretax net disallowance ranging from $80 million to $90 million. In addition, if AFUDC is ultimately determined to be included in the Texas jurisdictional capital cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $185 million related to revenues collected from February 2013 through December 2022 and such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis.

2016 Texas Base Rate Case

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

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

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) an 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 LA 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 and an order from the LPSC is expected in 2023.

2021 Arkansas Base Rate Case

In July 2021, SWEPCo filed a request with the APSC for an $85 million annual increase in Arkansas base rates based upon a proposed 10.35% ROE with a capital structure of 48.7% debt and 51.3% common equity. The proposed annual increase includes: (a) a $41 million revenue requirement for the North Central Wind Facilities, (b) a $14 million annual depreciation increase primarily due to recovery of the Dolet Hills Power Station through 2026 and Pirkey Plant and Welsh Plant, Units 1 and 3 through 2037 and (c) a $6 million increase due to SPP costs. In January 2022, SWEPCo filed testimony revising the requested annual increase in Arkansas base rates to $81 million. SWEPCo requested that rates become effective in June 2022.

In May 2022, the APSC issued a final order approving an annual revenue increase of $49 million based upon a 9.5% ROE. The order also includes: (a) a capital structure of 55% debt and 45% common equity, (b) approval to recover the Dolet Hills Power Station as a regulatory asset over five years without a return on this investment resulting in an immaterial disallowance in the second quarter of 2022, (c) the denial of accelerated depreciation for Pirkey Plant and Welsh Plant, Units 1 and 3 and (d) approval of a rider to recover SPP costs and revenues. The final order also denied the inclusion of the stand-alone NOLC in SWEPCo's deferred tax assets, but included approval of the deferral of the forgone revenue requirement associated with the NOLC and excess NOLC, with recovery of the deferral contingent upon receipt of a supportive private letter ruling from the IRS. Rates were implemented with the first billing cycle of July 2022.

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 October 2021, SWEPCo filed a request with the LPSC for recovery of $145 million in deferred storm costs associated with the three storms. As part of the filing, SWEPCo requested recovery of the carrying charges on the deferred regulatory asset at a weighted average cost of capital through a rider beginning in January 2022. In May 2022, LPSC staff testimony was submitted to the LPSC. In July 2022, SWEPCo filed rebuttal testimony which agreed to make a request for securitization as the LPSC staff had recommended in their testimony. An order is expected in 2023. If any of the storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

February 2021 Severe Winter Weather Impacts in SPP

As discussed in the "PSO Rate Matters" section above, 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 $329 million as of December 31, 2022, of which $75 million, $122 million and $132 million is related to the Arkansas, Louisiana and Texas jurisdictions, respectively.

In March 2021, the APSC issued an order authorizing recovery of the Arkansas jurisdictional share of the retail customer fuel costs over five years, with the appropriate carrying charge to be determined at a later date. Subsequently, SWEPCo began recovery of these fuel costs. In April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05%. In June 2022, the APSC ordered SWEPCo to recover the Arkansas jurisdictional share of the fuel costs over six years with a carrying charge equal to its weighted average cost of capital, subject to a prudency review and true-up.

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 of 3.25%. SWEPCo will work with the LPSC to finalize the actual recovery period and determine the appropriate carrying charge in future proceedings.

In August 2021, SWEPCo filed an application with the PUCT to implement a net interim fuel surcharge for the Texas jurisdictional share of these retail fuel costs. The application requested a five-year recovery with a carrying charge of 7.18%. In March 2022, the PUCT ordered SWEPCo to recover the Texas jurisdictional share of the fuel costs over five years with a carrying charge of 1.65% and ordered SWEPCo to file a fuel reconciliation addressing fuel costs from January 1, 2020 through December 31, 2021.

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 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 on the formal challenge which ruled in favor of the joint customers on several issues. Management has determined that the result of the order will have an immaterial impact to the financial statements of AEP, AEPTCo, PSO and SWEPCo. In November 2022, certain joint customers appealed the FERC decision to the U.S. Court of Appeals for the District of Columbia Circuit.

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. The PAPUC decision remains subject to the jurisdiction and review of the United States District Court for the Middle District of Pennsylvania, which had stayed review of the PAPUC decision until the Pennsylvania state court had ordered. The procedural schedule for this case states that a decision by the United States District Court for the Middle of Pennsylvania will not be reached until 2023.

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, 2022, AEP's share of IEC capital expenditures was approximately $87 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 Office of the Ohio Consumers' Counsel (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. A FERC order on rehearing is expected in 2023. Based on management's preliminary estimates, the December 2022 FERC order is expected to reduce AEP's pretax income by approximately $20 million on an annual basis.

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 AEGCo's unit power agreement with 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. It is expected that the FERC will issue an order on this review in the second half of 2023. This FERC review and subsequent order on these issues could reduce future net income and cash flows and impact financial conditions.

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 April 2016, Welsh Plant, Unit 2 was retired. As part of the 2016 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo's Texas jurisdictional share of Welsh Plant, Unit 2, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $7 million in 2017. See "2016 Texas Base Rate Case" section of Note 4 for additional information. As part of the 2019 Arkansas Base Rate Case, SWEPCo received approval from the APSC to recover the Arkansas jurisdictional share of Welsh Plant, Unit 2. In December 2020, SWEPCo filed a request with the LPSC to recover the Louisiana jurisdictional share of Welsh Plant, Unit 2. In January 2023, the LPSC approved a settlement agreement which provided recovery of Welsh Plant, Unit 2 as requested. See "2020 Louisiana Base Rate Case" section of Note 4 for additional information.

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", "2020 Louisiana Base Rate Case" and "2021 Arkansas Base Rate Case" sections of Note 4 for additional information.

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 2021 Oklahoma Base Rate Case, PSO will continue to recover Northeastern Plant, Unit 3 through 2040.

SWEPCo

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

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of December 31, 2022, 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	$ 136.3	$ 145.8	$ 20.2	(b)	2026	(c)	$ 14.9
Pirkey Plant	35.1	179.5	39.8		2023	(d)	11.7
Welsh Plant, Units 1 and 3	416.8	85.6	58.3	(e)	2028	(f)	37.9

(a) Represents the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(b) Includes Northeastern Plant, Unit 4, which was retired in 2016. Removal of Northeastern Plant, Unit 4, will be performed with Northeastern Plant, Unit 3, after retirement.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Pirkey Plant is currently being recovered through 2032 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(e) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with Welsh Plant, Units 1 and 3, after retirement.
(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 2020, management of SWEPCo and CLECO determined DHLC would not develop additional Oxbow Lignite Company (Oxbow) mining areas for future lignite extraction and ceased extraction of lignite at the mine in May 2020. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining. 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, 2022, SWEPCo's share of the net investment in the Dolet Hills Power Station is $112 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, 2022, SWEPCo had a net under-recovered fuel balance of $257 million, inclusive of costs related to 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 $32 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 $72 million, including denial of recovery of the $32 million deferral, with refunds to customers over five years. In September 2022, SWEPCo filed rebuttal testimony addressing the LPSC staff recommendations.

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 August 2022, SWEPCo filed a fuel reconciliation with the PUCT covering the fuel period of January 1, 2020 through December 31, 2021. Intervenor testimony is due in the first quarter of 2023 and a decision from the PUCT is expected in the third quarter of 2023.

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

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

In 2020, management announced plans to retire the Pirkey Plant in 2023. The Pirkey Plant non-fuel costs are recoverable by SWEPCo through base rates and rate riders. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized recovery of SWEPCo's Louisiana share of the Pirkey Plant through a separate rider. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of December 31, 2022, SWEPCo's share of the net investment in the Pirkey Plant is $215 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $43 million as of December 31, 2022. As of December 31, 2022, SWEPCo had a net under-recovered fuel balance of $257 million, inclusive of costs related to Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Upon cessation of lignite deliveries by Sabine to the Pirkey Plant, additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining
	2022	2021	Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 625.7	$ 409.4	1 year
Under-recovered Fuel Costs - does not earn a return	565.3	175.7	1 year
Unrecovered Winter Storm Fuel Costs - earns a return (a)	95.8	62.7	1 year
Total Current Regulatory Assets (b)	$ 1,286.8	$ 647.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Pirkey Plant Accelerated Depreciation	$ 116.5	$ 87.0	
Welsh Plant, Units 1 and 3 Accelerated Depreciation	85.6	45.9	
Unrecovered Winter Storm Fuel Costs	84.6	367.5	
Dolet Hills Power Station Fuel Costs - Louisiana	32.0	30.9	
Dolet Hills Power Station Accelerated Depreciation (c)	9.7	72.3	
Plant Retirement Costs - Unrecovered Plant, Louisiana	—	35.2	
Other Regulatory Assets Pending Final Regulatory Approval	27.2	9.2	
Total Regulatory Assets Currently Earning a Return	355.6	648.0	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	332.7	241.8	
2020-2022 Virginia Triennial Under-Earnings	37.9	15.1	
Plant Retirement Costs - Asset Retirement Obligation Costs	25.9	25.9	
Other Regulatory Assets Pending Final Regulatory Approval	53.9	55.1	
Total Regulatory Assets Currently Not Earning a Return	450.4	337.9	
Total Regulatory Assets Pending Final Regulatory Approval	806.0	985.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (d)	511.4	522.2	24 years
Long-term Under-recovered Fuel Costs - Oklahoma	252.7	—	2 years
Long-term Under-recovered Fuel Costs - Virginia	223.3	—	2 years
Unrecovered Winter Storm Fuel Costs (e)	148.6	679.3	5 years
Pirkey Plant Accelerated Depreciation - Louisiana	63.0	—	10 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	56.6	66.6	6 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station, Louisiana	45.1	—	10 years
Meter Replacement Costs	34.2	44.9	5 years
Environmental Control Projects	33.9	36.2	18 years
Cook Plant Uprate Project	25.3	27.7	11 years
Ohio Distribution Decoupling	19.5	41.6	2 years
Other Regulatory Assets Approved for Recovery	99.5	116.6	various
Total Regulatory Assets Currently Earning a Return	1,513.1	1,535.1	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	975.4	677.0	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	303.2	293.2	20 years
Unamortized Loss on Reacquired Debt	103.8	111.2	26 years
Cook Plant Nuclear Refueling Outage Levelization	81.2	32.0	3 years
Plant Retirement Costs - Unrecovered Plant, Texas	51.7	51.9	24 years
Peak Demand Reduction/Energy Efficiency	41.7	40.8	4 years
Unrealized Loss on Forward Commitments	40.1	100.8	10 years
Fuel and Purchased Power Adjustment Rider	38.1	12.1	2 years
Ohio Enhanced Service Reliability Plan	33.3	9.5	2 years
2017-2019 Virginia Triennial Under-Earnings	30.1	—	2 years
Postemployment Benefits	27.7	29.1	3 years
Vegetation Management	25.8	29.3	3 years
Smart Grid Costs	25.4	19.3	2 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	21.1	—	5 years
PJM/SPP Annual Formula Rate True-up	20.3	17.6	2 years
Virginia Transmission Rate Adjustment Clause	18.7	37.2	2 years
Storm-Related Costs	11.9	25.4	2 years
Texas Transmission Cost Recovery Factor	3.8	30.6	2 years
Other Regulatory Assets Approved for Recovery	108.8	104.3	various
Total Regulatory Assets Currently Not Earning a Return	1,962.1	1,621.3	
Total Regulatory Assets Approved for Recovery	3,475.2	3,156.4	
Total Noncurrent Regulatory Assets (f)	$ 4,281.2	$ 4,142.3	

(a) In 2022, Unrecovered Winter Storm Costs in the Arkansas and Texas jurisdictions were approved for recovery by the APSC and PUCT. As of December 31, 2022, Unrecovered Winter Storm Fuel Costs in the Louisiana jurisdiction are pending final regulatory approval with the LPSC. The current asset balance represents amounts expected to be recovered in the Arkansas, Louisiana and Texas jurisdiction over the next 12 months. See "February 2021 Severe Winter Weather Impacts in SPP" section of SWEPCo Rate Matters in Note 4 for additional information.
(b) Amounts exclude $23 million and $8 million as of December 31, 2022 and 2021, respectively, of Regulatory Asset for Under-Recovered Fuel Costs assets classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(c) 2022 amount includes the FERC jurisdiction. 2021 amounts include Arkansas, Louisiana and FERC jurisdictions.
(d) 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.
(e) In February 2022, the OCC approved PSO's securitization of the Unrecovered Winter Storm Fuel Costs. In September 2022, PSO received proceeds of $687 million from the ODFA which issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event, which were previously recorded as Regulatory Assets on PSO's balance sheet. See "February 2021 Severe Winter Weather Impacts in SPP" section of PSO Rate Matters in Note 4 for additional information.
(f) Amounts exclude $481 million and $477 million as of December 31, 2022 and 2021, respectively, of Regulatory Assets classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

	AEP		
	December 31,		Remaining
	2022	2021	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 1.4	$ —	1 year
Over-recovered Fuel Costs - does not pay a return	—	1.5	
Total Current Regulatory Liabilities	$ 1.4	$ 1.5	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	$ 148.6	$ 262.2	
Total Regulatory Liabilities Currently Paying a Return	148.6	262.2	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	2.0	0.2	
Total Regulatory Liabilities Currently Not Paying a Return	2.0	0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	150.6	262.4	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	3,315.3	3,172.1	(b)
Income Taxes, Net (a)	2,479.3	2,711.4	(c)
Rockport Plant, Unit 2 Accelerated Depreciation for Leasehold Improvements	53.8	4.2	6 years
Renewable Energy Surcharge - Michigan	23.2	14.9	2 years
Other Regulatory Liabilities Approved for Payment	9.5	16.1	various
Total Regulatory Liabilities Currently Paying a Return	5,881.1	5,918.7	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,318.5	1,939.7	(d)
Deferred Investment Tax Credits	237.3	248.5	34 years
OVEC Purchased Power	47.1	14.8	2 years
Spent Nuclear Fuel	45.8	49.5	(d)
Unrealized Gain on Forward Commitments	41.2	37.2	2 years
2017-2019 Virginia Triennial Revenue Provision	39.1	41.6	26 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	34.2	—	2 years
Over-recovered Fuel Costs - Ohio	32.2	15.2	10 years
PJM Transmission Enhancement Refund	32.1	42.9	3 years
Transition and Restoration Charges - Texas	29.4	26.3	7 years
Peak Demand Reduction/Energy Efficiency	28.6	28.6	2 years
Other Regulatory Liabilities Approved for Payment	82.4	60.9	various
Total Regulatory Liabilities Currently Not Paying a Return	1,967.9	2,505.2	
Total Regulatory Liabilities Approved for Payment	7,849.0	8,423.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits (e)	$ 7,999.6	$ 8,686.3	

(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 $237 million and $387 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 6 years.
(d) Relieved when plant is decommissioned.
(e) Amounts exclude $116 million and $148 million as of December 31, 2022 and 2021, respectively, of Regulatory Liabilities and Deferred Investment Tax Credits classified as Liabilities Held for Sale on the balance sheet. See “Disposition of KPCo and KTCo” section of Note 7 for additional information.

Regulatory Assets:	AEP Texas December 31, 2022	2021	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	26.7	22.4	
Vegetation Management Program	5.2	5.2	
Texas Retail Electric Provider Bad Debt Expense	4.1	4.1	
Other Regulatory Assets Pending Final Regulatory Approval	13.4	9.5	
Total Regulatory Assets Currently Not Earning a Return	49.4	41.2	
Total Regulatory Assets Pending Final Regulatory Approval	67.0	41.2	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	16.1	22.7	4 years
Advanced Metering System	—	10.6	
Other Regulatory Assets Approved for Recovery	1.4	2.1	various
Total Regulatory Assets Currently Earning a Return	17.5	35.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	173.2	119.0	12 years
Vegetation Management Program	12.1	17.4	3 years
Peak Demand Reduction/Energy Efficiency	11.9	14.5	2 years
Storm-Related Costs	8.5	12.8	2 years
Texas Transmission Cost Recovery Factor	3.8	30.6	2 years
Other Regulatory Assets Approved for Recovery	4.3	4.3	various
Total Regulatory Assets Currently Not Earning a Return	213.8	198.6	
Total Regulatory Assets Approved for Recovery	231.3	234.0	
Total Noncurrent Regulatory Assets	$ 298.3	$ 275.2	

Regulatory Liabilities:	AEP Texas		
	December 31,		Remaining Refund Period
	2022	2021	
	(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	1.8	—	
Total Regulatory Liabilities Currently Not Paying a Return	1.8	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	14.8	13.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	766.8	744.7	(b)
Income Taxes, Net (a)	431.6	445.3	(c)
Other Regulatory Liabilities Approved for Payment	4.3	4.8	various
Total Regulatory Liabilities Currently Paying a Return	1,202.7	1,194.8	
Regulatory Liabilities Currently Not Paying a Return			
Transition and Restoration Charges	29.4	26.3	7 years
Other Regulatory Liabilities Approved for Payment	12.7	7.9	various
Total Regulatory Liabilities Currently Not Paying a Return	42.1	34.2	
Total Regulatory Liabilities Approved for Payment	1,244.8	1,229.0	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,259.6	$ 1,242.0	

(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, 2022	2021	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	$ 6.8	$ 8.5	2 years
Total Regulatory Assets Approved for Recovery	6.8	8.5	
Total Noncurrent Regulatory Assets (a)	$ 6.8	$ 8.5	

Regulatory Liabilities:	AEPTCo December 31, 2022	2021	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (b)	$ 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	356.1	271.4	(c)
Income Taxes, Net (b)	350.2	364.0	(d)
Total Regulatory Liabilities Approved for Payment	706.3	635.4	
Total Noncurrent Regulatory Liabilities (e)	$ 715.0	$ 644.1	

(a) Amounts exclude $346 thousand and $0 as of December 31, 2022 and 2021, respectively, of Regulatory Assets classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(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. Excess ADIT that is Not Subject to Rate Normalization Requirements were $16 million and $26 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 6 years.
(e) Amounts exclude $8 million and $8 million as of December 31, 2022 and 2021, respectively, of Regulatory Liabilities classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

Regulatory Assets:	APCo December 31, 2022	APCo December 31, 2021	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 180.7	$ 127.2	1 year
Under-recovered Fuel Costs - does not earn a return	292.4	74.1	1 year
Total Current Regulatory Assets	$ 473.1	$ 201.3	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
COVID-19 - Virginia	$ 7.0	$ 6.8	
Total Regulatory Assets Currently Earning a Return	7.0	6.8	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - West Virginia	72.6	53.7	
2020-2022 Virginia Triennial Under-Earnings	37.9	15.1	
Plant Retirement Costs - Asset Retirement Obligation Costs	25.9	25.9	
Other Regulatory Assets Pending Final Regulatory Approval	1.1	3.6	
Total Regulatory Assets Currently Not Earning a Return	137.5	98.3	
Total Regulatory Assets Pending Final Regulatory Approval	144.5	105.1	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Long-term Under-recovered Fuel Costs - Virginia	223.3	—	2 years
Plant Retirement Costs - Unrecovered Plant	75.6	110.0	21 years
Other Regulatory Assets Approved for Recovery	0.4	0.4	various
Total Regulatory Assets Currently Earning a Return	299.3	110.4	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	303.1	293.1	15 years
Pension and OPEB Funded Status	108.3	62.7	12 years
Unamortized Loss on Reacquired Debt	74.4	78.2	23 years
2017-2019 Virginia Triennial Under-Earnings	30.1	—	2 years
Virginia Transmission Rate Adjustment Clause	18.7	37.2	2 years
Virginia Clean Economy Act	16.7	—	2 years
Peak Demand Reduction/Energy Efficiency	15.8	17.8	4 years
Postemployment Benefits	13.7	13.3	3 years
Vegetation Management Program - West Virginia	13.7	11.9	2 years
Environmental Compliance Costs	4.3	13.7	2 years
Other Regulatory Assets Approved for Recovery	16.0	14.2	various
Total Regulatory Assets Currently Not Earning a Return	614.8	542.1	
Total Regulatory Assets Approved for Recovery	914.1	652.5	
Total Noncurrent Regulatory Assets	$ 1,058.6	$ 757.6	

Regulatory Liabilities:	APCo December 31, 2022	APCo December 31, 2021	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)	$ 30.5	$ 4.5	
Total Regulatory Liabilities Pending Final Regulatory Determination	30.5	4.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	713.5	703.3	(b)
Income Taxes, Net (a)	291.3	432.9	(c)
Deferred Investment Tax Credits	0.3	0.3	31 years
Total Regulatory Liabilities Currently Paying a Return	1,005.1	1,136.5	
Regulatory Liabilities Currently Not Paying a Return			
2017-2019 Virginia Triennial Revenue Provision	39.1	41.6	26 years
Unrealized Gain on Forward Commitments	34.5	28.2	2 years
Over-recovered Deferred Wind Power Costs - Virginia	13.6	8.4	2 years
PJM Transmission Enhancement Refund	9.8	13.0	3 years
Other Regulatory Liabilities Approved for Payment	11.0	6.6	various
Total Regulatory Liabilities Currently Not Paying a Return	108.0	97.8	
Total Regulatory Liabilities Approved for Payment	1,113.1	1,234.3	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,143.6	$ 1,238.8	

(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 $19 million and $84 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 6 years.

Regulatory Assets:	I&M December 31, 2022	I&M December 31, 2021	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Michigan - earns a return	$ 9.0	$ 6.4	1 year
Under-recovered Fuel Costs, Indiana - does not earn a return	38.1	—	1 year
Total Current Regulatory Assets	$ 47.1	$ 6.4	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 0.1	
Total Regulatory Assets Currently Earning a Return	0.1	0.1	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - Indiana	21.6	—	
Other Regulatory Assets Pending Final Regulatory Approval	2.0	3.6	
Total Regulatory Assets Currently Not Earning a Return	23.6	3.6	
Total Regulatory Assets Pending Final Regulatory Approval	23.7	3.7	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	147.0	170.8	6 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	56.6	66.6	6 years
Cook Plant Uprate Project	25.3	27.7	11 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan, FERC	12.1	13.1	12 years
Cook Plant Turbine - Indiana	9.0	9.7	16 years
Cook Plant Study Costs	8.7	9.4	13 years
Other Regulatory Assets Approved for Recovery	11.9	6.0	various
Total Regulatory Assets Currently Earning a Return	270.6	303.3	
Regulatory Assets Currently Not Earning a Return			
Cook Plant Nuclear Refueling Outage Levelization	81.2	32.0	3 years
Pension and OPEB Funded Status	26.9	—	12 years
Unamortized Loss on Reacquired Debt	12.9	14.2	26 years
Peak Demand Energy Efficiency	10.3	2.8	2 years
Postemployment Benefits	7.7	9.0	3 years
Storm-Related Costs - Indiana	3.4	12.6	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	15.1	
Other Regulatory Assets Approved for Recovery	22.9	18.2	various
Total Regulatory Assets Currently Not Earning a Return	165.3	103.9	
Total Regulatory Assets Approved for Recovery	435.9	407.2	
Total Noncurrent Regulatory Assets	$ 459.6	$ 410.9	

Regulatory Liabilities:	I&M December 31, 2022	I&M December 31, 2021	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Indiana - does not pay a return	$ —	$ 1.5	
Total Current Regulatory Liabilities	$ —	$ 1.5	
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)	$ (87.7)	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	(87.7)	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	170.7	179.7	(c)
Income Taxes, Net (a)	168.6	182.6	(d)
Renewable Energy Surcharge - Michigan	23.2	14.9	2 years
Other Regulatory Liabilities Approved for Payment	3.0	7.0	various
Total Regulatory Liabilities Currently Paying a Return	365.5	384.2	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,318.5	1,939.7	(e)
Spent Nuclear Fuel	45.8	49.5	(e)
PJM Costs and Off-system Sales Margin Sharing - Indiana	34.2	—	2 years
Deferred Investment Tax Credits	17.4	22.4	28 years
Pension OPEB Funded Status	—	27.6	
Environmental Cost Rider - Indiana	—	10.6	
Other Regulatory Liabilities Approved for Payment	8.5	13.9	various
Total Regulatory Liabilities Currently Not Paying a Return	1,424.4	2,063.7	
Total Regulatory Liabilities Approved for Payment	1,789.9	2,447.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,702.2	$ 2,447.9	

(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 $42 million and $90 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 6 years.
(e) Relieved when plant is decommissioned.

Regulatory Assets:	OPCo December 31, 2022	2021	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	$ 33.8	$ 3.8	
Total Regulatory Assets Pending Final Regulatory Approval	33.8	3.8	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Distribution Decoupling	19.5	41.6	2 years
Ohio Basic Transmission Cost Rider	14.3	5.2	2 years
Ohio Economic Development Rider	1.1	10.1	2 years
Total Regulatory Assets Currently Earning a Return	34.9	56.9	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	142.7	83.3	12 years
Unrealized Loss on Forward Commitments	40.0	92.1	10 years
Ohio Enhanced Service Reliability Plan	33.3	9.5	2 years
Smart Grid Costs	25.4	19.3	2 years
Postemployment Benefits	6.2	6.2	3 years
PJM Load Service Entity Formula Rate True-up	—	7.5	
Other Regulatory Assets Approved for Recovery	11.0	14.4	various
Total Regulatory Assets Currently Not Earning a Return	258.6	232.3	
Total Regulatory Assets Approved for Recovery	293.5	289.2	
Total Noncurrent Regulatory Assets	$ 327.3	$ 293.0	

Regulatory Liabilities:	OPCo December 31, 2022	OPCo December 31, 2021	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	466.5	467.6	(a)
Income Taxes, Net (b)	451.9	480.6	(c)
Total Regulatory Liabilities Currently Paying a Return	918.4	948.2	
Regulatory Liabilities Currently Not Paying a Return			
OVEC Purchased Power	47.1	14.8	2 years
Over-recovered Fuel Costs	32.2	15.2	10 years
Peak Demand Reduction/Energy Efficiency	23.6	22.5	2 years
PJM Transmission Enhancement Refund	14.7	19.6	3 years
Other Regulatory Liabilities Approved for Payment	7.8	0.4	various
Total Regulatory Liabilities Currently Not Paying a Return	125.4	72.5	
Total Regulatory Liabilities Approved for Payment	1,043.8	1,020.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,044.0	$ 1,020.9	

(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 $162 million and $191 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 6 years.

Regulatory Assets:	PSO		
	December 31, 2022	December 31, 2021	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 178.7	$ 194.6	1 year
Total Current Regulatory Assets	$ 178.7	$ 194.6	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	$ 25.5	$ 13.9	
Other Regulatory Assets Pending Final Regulatory Approval	0.1	0.3	
Total Regulatory Assets Pending Final Regulatory Approval	25.6	14.2	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Long-term Under-recovered Fuel Costs - Oklahoma	252.7	—	2 years
Plant Retirement Costs - Unrecovered Plant (a)	240.6	227.6	24 years
Environmental Control Projects	23.9	25.2	18 years
Meter Replacement Costs	18.1	22.2	5 years
Storm-Related Costs	8.4	17.4	2 years
Unrecovered Winter Storm Fuel Costs	—	679.3	(b)
Other Regulatory Assets Approved for Recovery	9.1	9.8	various
Total Regulatory Assets Currently Earning a Return	552.8	981.5	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	55.2	22.9	12 years
Other Regulatory Assets Approved for Recovery	20.1	18.8	various
Total Regulatory Assets Currently Not Earning a Return	75.3	41.7	
Total Regulatory Assets Approved for Recovery	628.1	1,023.2	
Total Noncurrent Regulatory Assets	$ 653.7	$ 1,037.4	

(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.
(b) In February 2022, the OCC approved PSO's securitization of the Unrecovered Winter Storm Fuel Costs. In September 2022, PSO received proceeds of $687 million from the ODFA which issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event, which were previously recorded as Regulatory Assets on PSO's balance sheet. See "February 2021 Severe Winter Weather Impacts in SPP" section of PSO Rate Matters in Note 4 for additional information.

Regulatory Liabilities:	PSO December 31, 2022	PSO December 31, 2021	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	$ 56.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	51.3	56.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a)	380.1	423.8	(b)
Asset Removal Costs	316.3	300.2	(c)
Total Regulatory Liabilities Currently Paying a Return	696.4	724.0	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	48.2	50.8	22 years
Other Regulatory Liabilities Approved for Payment	13.2	4.3	various
Total Regulatory Liabilities Currently Not Paying a Return	61.4	55.1	
Total Regulatory Liabilities Approved for Payment	757.8	779.1	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 809.1	$ 835.3	

(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 $21 million and $46 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 2 years.
(c) Relieved as removal costs are incurred.

Regulatory Assets:	SWEPCo December 31, 2022	SWEPCo December 31, 2021	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 257.2	$ 81.2	1 year
Unrecovered Winter Storm Fuel Costs - earns a return (b)	95.8	62.7	1 year
Total Current Regulatory Assets	$ 353.0	$ 143.9	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Pirkey Plant Accelerated Depreciation	$ 116.5	$ 87.0	
Welsh Plant, Units 1 and 3 Accelerated Depreciation	85.6	45.9	
Unrecovered Winter Storm Fuel Costs (b)	84.6	367.5	
Dolet Hills Power Station Fuel Costs - Louisiana	32.0	30.9	
Dolet Hills Power Station Accelerated Depreciation (c)	9.7	72.3	
Plant Retirement Costs - Unrecovered Plant, Louisiana	—	35.2	
Other Regulatory Assets Pending Final Regulatory Approval	2.5	2.4	
Total Regulatory Assets Currently Earning a Return	330.9	641.2	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - Louisiana	151.5	148.0	
Asset Retirement Obligation - Louisiana	11.8	10.3	
Other Regulatory Assets Pending Final Regulatory Approval	16.0	18.4	
Total Regulatory Assets Currently Not Earning a Return	179.3	176.7	
Total Regulatory Assets Pending Final Regulatory Approval	510.2	817.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Unrecovered Winter Storm Fuel Costs (b)	148.6	—	5 years
Pirkey Plant Accelerated Depreciation - Louisiana	63.0	—	10 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station - Louisiana	45.1	—	10 years
Plant Retirement Costs - Unrecovered Plant, Welsh Plant, Unit 2 - Louisiana	35.2	—	10 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	13.1	13.7	20 years
Environmental Controls Projects	10.0	11.0	10 years
Other Regulatory Assets Approved for Recovery	6.8	5.2	various
Total Regulatory Assets Currently Earning a Return	321.8	29.9	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	96.2	73.8	12 years
Plant Retirement Costs - Unrecovered Plant, Texas	51.7	51.9	24 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	21.1	—	5 years
Dolet Hills Power Station Fuel Costs - Arkansas	8.9	13.0	4 years
Other Regulatory Assets Approved for Recovery	32.5	18.8	various
Total Regulatory Assets Currently Not Earning a Return	210.4	157.5	
Total Regulatory Assets Approved for Recovery	532.2	187.4	
Total Noncurrent Regulatory Assets	$ 1,042.4	$ 1,005.3	

(a) 2022 amount includes Arkansas and Texas jurisdictions. 2021 amount includes Arkansas, Louisiana and Texas jurisdictions.

(b) In 2022, Unrecovered Winter Storm Costs in the Arkansas and Texas jurisdictions were approved for recovery by the APSC and PUCT. As of December 31, 2022, Unrecovered Winter Storm Fuel Costs in the Louisiana jurisdiction are pending final regulatory approval with the LPSC. The current asset balance represents amounts expected to be recovered in the Arkansas, Louisiana and Texas jurisdiction over the next 12 months. See "February 2021 Severe Winter Weather Impacts in SPP" section of SWEPCo Rate Matters in Note 4 for additional information.

(c) 2022 amount includes the FERC jurisdiction. 2021 amounts include Arkansas, Louisiana and FERC jurisdictions.

Regulatory Liabilities:	SWEPCo December 31, 2022	SWEPCo December 31, 2021	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return (a)	$ 1.4	$ —	
Total Current Regulatory Liabilities	$ 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	$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	7.0	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	481.2	461.3	(c)
Income Taxes, Net (b)	327.6	330.2	(d)
Other Regulatory Liabilities Approved for Payment	2.2	2.4	various
Total Regulatory Liabilities Currently Paying a Return	811.0	793.9	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Approved for Payment	7.7	13.0	various
Total Regulatory Liabilities Currently Not Paying a Return	7.7	13.0	
Total Regulatory Liabilities Approved for Payment	818.7	806.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 825.7	$ 806.9	

(a) 2022 amount includes 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. Excess ADIT that is Not Subject to Rate Normalization Requirements were $7 million and $7 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 1 year.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

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

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

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

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2022:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,499.8	$ 1,711.8	$ 345.4	$ 252.0	$ 3,809.0
Energy and Capacity Purchase Contracts	167.8	377.7	349.1	570.5	1,465.1
Total	$ 1,667.6	$ 2,089.5	$ 694.5	$ 822.5	$ 5,274.1

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 840.9	$ 1,102.9	$ 263.2	$ 9.2	$ 2,216.2
Energy and Capacity Purchase Contracts	40.5	82.7	79.9	127.0	330.1
Total	$ 881.4	$ 1,185.6	$ 343.1	$ 136.2	$ 2,546.3

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 200.9	$ 235.2	$ 53.3	$ 222.4	$ 711.8
Energy and Capacity Purchase Contracts	140.9	290.0	273.8	276.8	981.5
Total	$ 341.8	$ 525.2	$ 327.1	$ 499.2	$ 1,693.3

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 34.4	$ 66.5	$ 63.7	$ 169.8	$ 334.4

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 35.8	$ 14.5	$ —	$ —	$ 50.3
Energy and Capacity Purchase Contracts	47.1	116.3	122.8	91.4	377.6
Total	$ 82.9	$ 130.8	$ 122.8	$ 91.4	$ 427.9

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 133.7	$ 84.7	$ —	$ —	$ 218.4
Energy and Capacity Purchase Contracts	10.1	31.6	13.2	—	54.9
Total	$ 143.8	$ 116.3	$ 13.2	$ —	$ 273.3

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

GUARANTEES

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

Letters of Credit (Applies to AEP and AEP Texas)

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

AEP has $4 billion and $1 billion revolving credit facilities due in March 2027 and 2024, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2022, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under five uncommitted facilities totaling, as of December 31, 2022, $400 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2022 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 287.4	January 2023 to December 2023
AEP Texas	1.8	July 2023

Guarantees of Equity Method Investees (Applies to AEP)

In 2019, AEP acquired a 50% ownership interest in five non-consolidated renewable joint ventures and two renewable tax equity partnerships. Parent issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. In September 2022, AEP signed a PSA with a nonaffiliate for AEP's interest in Flat Ridge 2, one of the five non-consolidated joint ventures. The transaction closed in the fourth quarter of 2022. As of December 31, 2022, the maximum potential amount of future payments associated with the remaining guarantees was $59 million, with the last guarantee expiring in December 2035. The non-contingent liability recorded associated with these guarantees was $5 million, with an additional $1 million expected credit loss liability for the contingent portion of the guarantees. In accordance with the accounting guidance for guarantees, the initial recognition of the non-contingent liabilities increased AEP's carrying values of the respective equity method investees. Management considered historical losses, economic conditions, and reasonable and supportable forecasts in the calculation of the expected credit loss. As the joint ventures generate cash flows through PPAs, the measurement of the contingent portion of the guarantee liability is based upon assessments of the credit quality and default probabilities of the respective PPA counterparties.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2022, there were no material liabilities recorded for any indemnifications.

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

Lease Obligations

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

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2022, 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. I&M

has also been named potentially liable at two sites under state law and AEP Texas and SWEPCo share potential liability under state law at another site. 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, 2022, 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, $4 million and $4 million for the years ended December 31, 2022, 2021 and 2020, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2022 and 2021, the total decommissioning trust fund balances were $3 billion and $3.5 billion, respectively. The decrease in the trust fund balance was driven by unfavorable investment performance in 2022. 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, 2022 and 2021, fees and related interest of $286 million and $281 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 $330 million and $329 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 $3 million, $14 million and $24 million in 2022, 2021 and 2020, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2022. The proceeds reduced costs for dry cask storage. As of December 31, 2022 and 2021, I&M deferred $21 million and $3 million, respectively, in Prepayments and Other Current Assets and $3 million and $21 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 $41 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $13.7 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $450 million of 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 $275 million per nuclear incident on Cook Plant's reactors payable in annual installments of $41 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $450 million through commercially available insurance. The next level of liability coverage of up to $13.2 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

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

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

In 2013, the Wilmington Trust Company filed suit in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs sought a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs.

After the litigation proceeded at the district court and appellate court, in April 2021, I&M and AEGCo reached an agreement to acquire 100% of the interests in Rockport Plant, Unit 2 for $116 million from certain financial institutions that own the unit through trusts established by Wilmington Trust, the nonaffiliated owner trustee of the ownership interests in the unit. The transaction closed at the expiration of the Rockport Plant, Unit 2 lease in December 2022 and also resulted in a final settlement of, and release of claims in, the lease litigation.

Subsequent to the end of the Rockport Plant, Unit 2 lease in December 2022, AEGCo's 50% ownership share of Rockport Plant, Unit 2 is being billed to I&M under a FERC-approved UPA. I&M's purchased power from AEGCo and I&M's 50% ownership share of Rockport Plant, Unit 2 electricity generated represent a merchant resource for I&M until Rockport Plant, Unit 2 is retired in 2028. A 2021 IURC order approved a settlement agreement addressing the future use of Rockport Plant, Unit 2 as a short-term capacity resource through the June 2023 - May 2024 PJM planning year. The MPSC issued an order in February 2023 approving the settlement agreement on I&M's 2022 Integrated Resource Plan (IRP) filing, which included certain cost recovery for the remaining net book value of leasehold improvements made during the term of the Rockport Plant, Unit 2 lease and future use of Rockport Plant, Unit 2 as a capacity resource. If I&M cannot recover its future investment and expenses related to the merchant share of Rockport Plant Unit 2, it could reduce future net income and cash flows and impact financial condition.

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

Four participants in The American Electric Power System Retirement Plan (the Plan) filed a class action complaint in December 2021 in the U.S. District Court for the Southern District of Ohio against AEPSC and the Plan. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The plaintiffs assert a number of claims on behalf of themselves and the purported class, including that: (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career, (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act and (c) AEP failed to provide required notice regarding the changes to the Plan. Among other relief, the Complaint seeks reformation of the Plan to provide additional benefits and the recovery of plan benefits for former employees under such reformed plan. The plaintiffs previously had submitted claims for additional plan benefits to AEP, which were denied. On February 15, 2022, AEPSC and the Plan filed a motion to dismiss the complaint for failure to state a claim. On August 16, 2022, the district court granted the motion to dismiss the complaint without prejudice. The plaintiffs filed a motion for leave to file an amended complaint, which the Court denied on December 1, 2022. The plaintiffs did not file an appeal by the deadline of January 3, 2023.

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. The amended complaint alleged misrepresentations or omissions by AEP regarding: (a) its alleged participation in or connection to public corruption with respect to the passage of HB 6 and (b) its regulatory, legislative, political contribution, 501(c)(4) organization contribution and lobbying activities in Ohio. The complaint sought monetary damages, among other forms of relief. 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 on April 29, 2022. On September 13, 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiffs subsequently filed a notice of appeal with the New York appellate court. On January 20, 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York on January 24, 2023. AEP filed a brief in opposition to intervention on February 3, 2023. 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 on May 3, 2022 and briefing on the motion to dismiss has been completed. Discovery remains stayed pending the district court's ruling on the motion to dismiss. The plaintiff in the Ohio state court case advised that they no longer agreed to stay the proceedings, therefore, AEP filed a motion to continue the stays of proceedings on May 20, 2022 and the plaintiff filed an amended complaint on June 2, 2022. On June 15, 2022, the Ohio state court entered an order continuing the stays of that case until the resolution of the consolidated derivative actions pending in Ohio federal district court. 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 is directed to the Board of Directors of AEP and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by directors and officers, and that, following such investigation, AEP commence a civil action for breaches of fiduciary duty and related claims and take appropriate disciplinary action against those individuals who allegedly harmed the company. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect.

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. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this investigation will have a material impact on financial condition, results of operations or cash flows.

Claims for Indemnification Related to Damages Resulting from the Federal EPA's Denial of Alternative Closure Deadline for Gavin Plant and Associated Findings of Compliance

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 determinations related to the CCR Rule (see "Environmental Issues - Coal Combustion Residual (CCR) Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information), including a determination 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 the Gavin Denial, as well as any future enforcement or litigation resulting from the Federal EPA's determinations of noncompliance with various aspects of the CCR Rule as part of the Gavin Denial. 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.

7. ACQUISITIONS, ASSETS AND LIABILITIES HELD FOR SALE, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

2021

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

In November 2020, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% ownership interest in the entity that owns the 100 MW Dry Lake Solar Project (collectively referred to as Dry Lake) located in southern Nevada for approximately $114 million. In March 2021, AEP closed the transaction and the solar project was placed in-service in May 2021. Approximately $103 million of the purchase price was paid upon closing of the transaction and the remaining $11 million was paid when the project was placed in-service. In accordance with the accounting guidance for "Business Combinations," management determined that the acquisition of Dry Lake represents an asset acquisition. Additionally, and in accordance with the accounting guidance for "Consolidation," management concluded that Dry Lake is a VIE and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact Dry Lake's economic performance. As the primary beneficiary of Dry Lake, AEP consolidates Dry Lake into its financial statements. As a result, to account for the initial consolidation of Dry Lake, management applied the acquisition method by allocating the purchase price based on the relative fair value of the assets acquired and noncontrolling interest assumed. The fair value of the primary assets acquired and the noncontrolling interest assumed was determined using the market approach. The key input assumptions were the transaction price paid for AEP's interest in Dry Lake and recent third-party market transactions for similar solar generation facilities. See 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, the first of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Sundance assets in proportion to their undivided ownership interests. Sundance was placed in-service in April 2021.

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

In 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, the third of the three NCWF acquisitions. 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.

In accordance with the guidance for "Business Combinations," management determined that the acquisitions of the NCWF projects represent asset acquisitions. As of December 31, 2022 and 2021, PSO had approximately $901 million and $316 million and SWEPCo had approximately $1.1 billion and $378 million, respectively, of gross Property, Plant and Equipment on the balance sheets related to the NCWF projects. On an ongoing basis, management further determined that PSO and SWEPCo should apply the joint plant accounting model to account for their respective undivided interests in the assets, liabilities, revenues and expenses of the NCWF projects.

The respective Purchase and Sale Agreements (PSAs) include collective interests in numerous land contracts, as originally executed between the nonaffiliated party and the respective owners of the properties as defined in the contracts. These contracts provide for easement and access rights to the land that Sundance, Maverick and Traverse were built upon. The lessee interests in the land contracts were transferred to Sundance, Maverick and Traverse (and subsequently to PSO and SWEPCo) as a part of the closings of the respective PSAs. The current Obligations Under Operating Leases related to the NCWF projects were not material as of December 31, 2022 and 2021 for PSO and SWEPCo. See the table below for the noncurrent Obligations Under Operating Leases for the NCWF projects for PSO and SWEPCo:

	PSO		SWEPCo	
	December 31, 2022	December 31, 2021	December 31, 2022	December 31, 2021
	(in millions)			
Project				
Sundance	$ 12.6	$ 12.6	$ 15.1	$ 15.1
Maverick	18.0	18.0	21.6	21.6
Traverse	39.8	—	47.7	—
Total	$ 70.4	$ 30.6	$ 84.4	$ 36.7

<u>2020</u>

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

In August 2020, AEP exercised its call right which required the nonaffiliated member of Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively the LLCs) to sell its noncontrolling interest to AEP. The exercise price for the call right was determined using a discounted cash flow model with agreed input assumptions as well as updates to certain assumptions reasonably expected based on the actual results of the LLCs. As a result, the LLCs are wholly-owned by AEP and management has concluded that the LLCs are no longer VIEs. AEP paid $57 million in cash, derecognized $63 million of Redeemable Noncontrolling Interest within Mezzanine Equity and recorded an increase of $6 million of Paid-In Capital on the balance sheets. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

Santa Rita East (Generation & Marketing Segment) (Applies to AEP)

In November 2020, AEP acquired an additional 10% interest in Santa Rita East for approximately $44 million resulting in AEP having a total interest of 85%. The acquisition of the incremental ownership interest was accounted for as an equity transaction in accordance with the accounting guidance for "Consolidation" and reduced Noncontrolling Interests on the balance sheets by approximately $44 million. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

ASSETS AND LIABILITIES HELD FOR SALE

2022

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. In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. AEP has received clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR) and the Committee on Foreign Investment in the United States during 2022. Clearance under the HSR expired in January 2023. AEP and Liberty refiled a joint application seeking HSR clearance in February 2023. The sale is also contingent upon FERC approval under Section 203 of the Federal Power Act. The parties to the SPA have certain termination rights if the closing of the sale does not occur by April 26, 2023.

Transfer of Ownership

FERC Proceedings

In December 2021, Liberty, KPCo and KTCo (the applicants) requested FERC approval of the sale under Section 203 of the Federal Power Act. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission rates of applicants. In April 2022, the FERC issued a deficiency letter stating that the Section 203 application is deficient and that additional information is required to process it. In May 2022, Liberty, KPCo and KTCo supplemented the application. 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 January 2023, AEP, AEPTCo, and Liberty entered into an amendment to the SPA that specified the applicants will submit a new filing for approval under Section 203 of the Federal Power Act. The new filing was submitted to the FERC on February 14, 2023. The applicants requested expedited treatment of the new filing, including an accelerated comment period. In response, the FERC granted a shortened 45 day comment period. The applicants believe the new Section 203 application addresses the concerns raised in the FERC's December 2022 order. The application contains several additional commitments by Liberty to mitigate potential adverse impacts on FERC jurisdictional rates over the next five years, including: a) maintaining the current return on equity; b) maintaining the current cost cap on equity; c) financing future investments at the current credit rating; and d) capping certain operating and administrative costs. The sale remains subject to FERC approval. The statute requires an order from the FERC within 180 days of the February 14, 2023 filing date in accordance with Section 203 of the Federal Power Act.

KPSC Proceedings

In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to conditions contingent upon the closing of the sale, including establishment of regulatory liabilities to subsidize retail customer transmission and distribution expenses, a fuel adjustment clause bill credit, and a three-year Big Sandy decommissioning rider rate holiday during which KPCo's carrying charge is reduced by 50%.

Mitchell Plant Operations and Maintenance Agreement and Ownership Agreement

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant. As of December 31, 2022 and 2021, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $577 million and $586 million, respectively. The SPA includes a condition precedent to closing requiring the issuance of regulatory orders approving new Mitchell Plant agreements.

The KPSC and WVPSC issued orders proposing materially different modifications to the Mitchell Plant agreements filed by AEP such that the new agreements could not be executed by the parties. In lieu of new agreements, in July 2022, KPCo and WPCo confirmed with the KPSC and WVPSC, respectively, that they will continue operating under the existing Mitchell Agreement, utilizing the Mitchell Agreement Operating Committee's authority under that agreement to issue appropriate resolutions so the parties can operate in accordance with each state commission's directives related to CCR and ELG investment. In September 2022, pursuant to resolutions under the existing Mitchell Plant agreement, WPCo replaced KPCo as the Operator of Mitchell Plant.

Summary

As a result of the conditions imposed by the KPSC's May 2022 order, in the second quarter of 2022, AEP recorded a $69 million loss on the expected sale of the Kentucky Operations in accordance with accounting guidance for Fair Value Measurement.

In September 2022, AEP, AEPTCo and Liberty entered into an amendment to the SPA which reduced the purchase price to approximately $2.646 billion and Liberty agreed to waive, upon FERC approval of the sale, the SPA condition precedent to closing requiring the issuance of regulatory orders approving new proposed Mitchell Plant agreements. Further, as a result of the reduced purchase price from the September Amendment and the change to the anticipated timing of the completion of the transaction, AEP recorded an additional $194 million pretax loss ($149 million net of tax) on the expected sale of the Kentucky Operations in the third quarter of 2022 in accordance with the accounting guidance for Fair Value Measurement.

As a result of the December 2022 FERC order and resulting delay in the anticipated timing of the closing of the transaction, AEP recorded an additional $100 million pretax loss ($79 million net of tax) on the expected sale of the Kentucky Operations in December 2022 in accordance with the accounting guidance for Fair Value Measurement. In total, AEP recorded a $363 million pretax loss of ($297 million net of tax) on the expected sale of the Kentucky Operations for the twelve months ended December 31, 2022.

Management believes it is probable that FERC authorization under Section 203 of the Federal Power Act will be received and closing will occur after receipt of the order. Therefore, the assets and liabilities of KPCo and KTCo were classified as Held for Sale in the December 31, 2022 balance sheets of AEP and AEPTCo. Upon closing, Liberty will acquire the assets and assume the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction. AEP expects cash proceeds, net of taxes and transaction fees, from the sale of approximately $1.2 billion. AEP plans to use the proceeds from the sale to fund its continued investment in regulated businesses, including transmission and regulated renewables projects. If additional reductions in the fair value of the Kentucky Operations occur, it would reduce future net income and cash flows.

Because the depreciation of Kentucky assets will continue to be reflected in revenues through customer rates until the expected closing of the transaction and will be reflected in the carryover basis of the rate-regulated assets once sold, AEP and AEPTCo will continue to recognize depreciation on those assets through the close of the transaction. Depreciation expense of $99 million and $4 million associated with KPCo and KTCo was recognized for the year ended December 31, 2022.

The Income Before Income Tax Expense (Benefit) of KPCo and KTCo were not material to AEP and AEPTCo on their respective statements of income for the twelve months ended December 31, 2022 and 2021.

The major classes of KPCo and KTCo's assets and liabilities presented in Assets Held for Sale and Liabilities Held for Sale on the balance sheets of AEP and AEPTCo are shown in the table below:

	AEP		AEPTCo	
	December 31, 2022	December 31, 2021	December 31, 2022	December 31, 2021
	(in millions)			
ASSETS				
Accounts Receivable and Accrued Unbilled Revenues	$ 97.7	$ 33.2	$ 1.8	$ 1.5
Fuel, Materials and Supplies	48.2	30.6	—	—
Property, Plant and Equipment, Net	2,419.4	2,302.7	169.8	165.3
Regulatory Assets	504.1	484.7	0.3	—
Other Classes of Assets that are not Major	51.3	68.5	6.1	1.1
Total Major Classes of Assets Held for Sale	3,120.7	2,919.7	178.0	167.9
Loss on the Expected Sale of Kentucky Operations (net of $66.1 million of Income Taxes)	(297.2)	—	—	—
Assets Held for Sale	$ 2,823.5	$ 2,919.7	$ 178.0	$ 167.9
LIABILITIES				
Accounts Payable	$ 57.8	$ 53.4	$ 1.5	$ 1.1
Long-term Debt Due Within One Year	490.0	200.0	—	—
Customer Deposits	38.8	32.4	—	—
Deferred Income Taxes	469.7	441.6	16.1	15.4
Long-term Debt	688.4	903.1	—	—
Regulatory Liabilities and Deferred Investment Tax Credits	116.0	148.1	8.2	7.6
Other Classes of Liabilities that are not Major	95.0	102.3	2.8	3.5
Liabilities Held for Sale	$ 1,955.7	$ 1,880.9	$ 28.6	$ 27.6

DISPOSITIONS

2022

Disposition of Cardinal Plant (Generation & Marketing Segment) (Applies to AEP)

In March 2022, AGR entered into an Asset Purchase agreement with a nonaffiliated electric cooperative to sell Cardinal Plant, Unit 1, a competitive generation asset totaling 595 MWs. The FERC approved the sale in May 2022 and the sale closed in the third quarter of 2022. The proceeds from the sale were not material. Concurrent with the closing of the sale, AGR executed a PPA with the nonaffiliated electric cooperative for rights to Unit 1's power and capacity through 2028. AGR also retained certain obligations related to environmental remediation.

Subsequent to the closing of the sale, AGR continues to recognize Cardinal Plant, Unit 1 on its balance sheet due to continuing involvement through the PPA. As of December 31, 2022, the net book value of Cardinal Plant, Unit 1 was not material.

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.

2021

Disposition of Racine (Generation & Marketing Segment) (Applies to AEP)

In February 2021, AEP signed an agreement to sell Racine to a nonaffiliated party. The sale of Racine closed in the fourth quarter of 2021 resulting in an immaterial gain which is recorded in Other Operation on AEP's statements of income.

2020

Conesville Plant (Generation & Marketing Segment) (Applies to AEP)

In June 2020, AEP and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated third-party related to the merchant Conesville Plant site. The purchaser took ownership of the assets and assumed responsibility for environmental liabilities, including ash pond closure, asbestos abatement and decommissioning and demolition of the Conesville Plant site. In consideration of the transfer of the acquired assets to the purchaser and the purchaser's assumption of liabilities, AEP paid approximately $98 million over three years, derecognized $106 million in ARO and recorded an immaterial gain on the transaction which is recorded in Other Operation on the statements of income. AEP paid approximately $26 million at closing in June 2020 and made additional payments totaling $72 million in quarterly installments from October 2020 to June 2022.

Oklaunion Power Station (Transmission and Distribution Segment and Vertically Integrated Utilities Segment) (Applies to AEP, AEP Texas and PSO)

In October 2020, AEP Texas, PSO and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated third-party related to the Oklaunion Power Station site. The purchaser took ownership of the assets and assumed responsibility for environmental liabilities, including ash pond closure, asbestos abatement and decommissioning and demolition of the Oklaunion Power Station site. The sale had an immaterial impact on the financial statements in the fourth quarter of 2020.

IMPAIRMENTS

2022

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 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.

2021

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.

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

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

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. The Registrants recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for 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	**2022**	**2021**	**2022**	**2021**
Discount Rate	5.50 %	2.90 %	5.50 %	2.90 %
Interest Crediting Rate	4.25 %	4.00 %	NA	NA

NA Not applicable.

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

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 2022, 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	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
Discount Rate	2.90 %	2.50 %	3.25 %	2.90 %	2.55 %	3.30 %
Interest Crediting Rate	4.00 %	4.00 %	4.00 %	NA	NA	NA
Expected Return on Plan Assets	5.25 %	4.75 %	5.75 %	5.50 %	4.75 %	5.50 %

NA Not applicable.

	Pension Plans		
	Year Ended December 31,		
Assumption – Rate of Compensation Increase (a)	**2022**	**2021**	**2020**
AEP	5.05 %	5.10 %	5.00 %
AEP Texas	5.15 %	5.10 %	5.05 %
APCo	4.90 %	4.85 %	4.85 %
I&M	5.00 %	5.00 %	5.00 %
OPCo	5.35 %	5.30 %	5.25 %
PSO	5.15 %	5.10 %	5.05 %
SWEPCo	5.00 %	4.95 %	4.90 %

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

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

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

	December 31,	
Health Care Trend Rates	**2022**	**2021**
Initial	7.50 %	6.25 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2029	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, 2022, 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, 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. For the year ended December 31, 2021, the pension plans had an actuarial gain primarily due to an increase in the discount rate, partially offset by less favorable demographic experience than expected, resulting from the updated census information as of January 1, 2021. For the year ended December 31, 2021, the OPEB plans had an actuarial gain primarily due to an increase in the discount rate and an update of the projected reimbursements from the Employer Group Waiver Program under Medicare Part D. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 5,187.0	$ 5,544.5	$ 1,041.3	$ 1,210.9
Service Cost	123.1	129.2	7.4	9.5
Interest Cost	148.2	137.2	29.2	30.5
Actuarial Gain	(983.4)	(173.9)	(109.8)	(120.1)
Plan Amendments	—	—	—	(5.4)
Benefit Payments	(402.2)	(450.0)	(140.1)	(126.0)
Participant Contributions	—	—	44.1	41.3
Medicare Subsidy	—	—	0.5	0.6
Benefit Obligation as of December 31,	$ 4,072.7	$ 5,187.0	$ 872.6	$ 1,041.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 5,352.9	$ 5,556.6	$ 2,044.3	$ 1,946.7
Actual Gain (Loss) on Plan Assets	(833.7)	239.2	(403.6)	176.5
Company Contributions (a)	7.7	7.1	4.6	5.8
Participant Contributions	—	—	44.1	41.3
Benefit Payments	(402.2)	(450.0)	(140.1)	(126.0)
Fair Value of Plan Assets as of December 31,	$ 4,124.7	$ 5,352.9	$ 1,549.3	$ 2,044.3
Funded Status as of December 31,	$ 52.0	$ 165.9	$ 676.7	$ 1,003.0

(a) No contributions were made to the qualified pension plan for the years ended December 31, 2022 and 2021, respectively. Contributions to the non-qualified pension plans were $8 million and $7 million for the years ended December 31, 2022 and 2021, respectively.

AEP	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 113.4	$ 244.3	$ 699.5	$ 1,040.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.3)	(7.6)	(2.5)	(2.7)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(55.1)	(70.8)	(20.3)	(35.1)
Funded Status	$ 52.0	$ 165.9	$ 676.7	$ 1,003.0

AEP Texas	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 419.8	$ 453.2	$ 80.5	$ 96.3
Service Cost	11.1	11.8	0.5	0.7
Interest Cost	12.1	11.2	2.2	2.4
Actuarial Gain	(67.8)	(10.9)	(7.1)	(12.3)
Plan Amendments	—	—	—	(0.5)
Benefit Payments	(41.1)	(45.5)	(10.9)	(9.3)
Participant Contributions	—	—	3.4	3.2
Benefit Obligation as of December 31,	$ 334.1	$ 419.8	$ 68.6	$ 80.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 444.9	$ 474.0	$ 168.8	$ 162.3
Actual Gain (Loss) on Plan Assets	(69.2)	16.0	(33.0)	12.5
Company Contributions	0.5	0.4	—	0.1
Participant Contributions	—	—	3.4	3.2
Benefit Payments	(41.1)	(45.5)	(10.9)	(9.3)
Fair Value of Plan Assets as of December 31,	$ 335.1	$ 444.9	$ 128.3	$ 168.8
Funded Status as of December 31,	$ 1.0	$ 25.1	$ 59.7	$ 88.3

AEP Texas	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 3.7	$ 28.7	$ 59.7	$ 88.3
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.3)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(2.3)	(3.3)	—	—
Funded Status	$ 1.0	$ 25.1	$ 59.7	$ 88.3

APCo	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 621.7	$ 670.8	$ 167.3	$ 198.2
Service Cost	11.4	11.9	0.8	1.0
Interest Cost	17.5	16.4	4.7	4.9
Actuarial Gain	(123.1)	(28.5)	(16.2)	(21.4)
Plan Amendments	—	—	—	(0.9)
Benefit Payments	(41.8)	(48.9)	(23.0)	(21.3)
Participant Contributions	—	—	7.0	6.6
Medicare Subsidy	—	—	0.1	0.2
Benefit Obligation as of December 31,	$ 485.7	$ 621.7	$ 140.7	$ 167.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 683.3	$ 701.3	$ 302.3	$ 293.0
Actual Gain (Loss) on Plan Assets	(109.8)	30.9	(59.3)	21.9
Company Contributions	—	—	1.6	2.1
Participant Contributions	—	—	7.0	6.6
Benefit Payments	(41.8)	(48.9)	(23.0)	(21.3)
Fair Value of Plan Assets as of December 31,	$ 531.7	$ 683.3	$ 228.6	$ 302.3
Funded Status as of December 31,	$ 46.0	$ 61.6	$ 87.9	$ 135.0

APCo	Pension Plans		OPEB	
	December 31,			
	2022	2021	2022	2021
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 46.6	$ 62.4	$ 106.3	$ 158.1
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(1.6)	(1.8)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(0.6)	(0.8)	(16.8)	(21.3)
Funded Status	$ 46.0	$ 61.6	$ 87.9	$ 135.0

I&M	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 612.1	$ 653.3	$ 118.6	$ 141.4
Service Cost	16.2	17.5	0.9	1.3
Interest Cost	17.0	16.2	3.4	3.5
Actuarial Gain	(138.0)	(29.5)	(8.7)	(16.8)
Plan Amendments	—	—	—	(0.7)
Benefit Payments	(40.5)	(45.4)	(18.3)	(15.3)
Participant Contributions	—	—	6.0	5.2
Benefit Obligation as of December 31,	$ 466.8	$ 612.1	$ 101.9	$ 118.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 681.5	$ 698.1	$ 248.7	$ 238.2
Actual Gain (Loss) on Plan Assets	(107.4)	28.8	(45.9)	20.6
Company Contributions	0.1	—	—	—
Participant Contributions	—	—	6.0	5.2
Benefit Payments	(40.5)	(45.4)	(18.3)	(15.3)
Fair Value of Plan Assets as of December 31,	$ 533.7	$ 681.5	$ 190.5	$ 248.7
Funded Status as of December 31,	$ 66.9	$ 69.4	$ 88.6	$ 130.1

	Pension Plans		OPEB	
	December 31,			
I&M	2022	2021	2022	2021
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 68.5	$ 71.4	$ 88.6	$ 130.1
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.1)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.5)	(1.9)	—	—
Funded Status	$ 66.9	$ 69.4	$ 88.6	$ 130.1

OPCo	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 470.7	$ 510.3	$ 104.9	$ 126.4
Service Cost	11.2	11.4	0.6	0.8
Interest Cost	13.3	12.5	3.0	3.0
Actuarial Gain	(97.9)	(24.1)	(8.9)	(15.6)
Plan Amendments	—	—	—	(0.6)
Benefit Payments	(33.7)	(39.4)	(15.5)	(13.6)
Participant Contributions	—	—	4.8	4.5
Benefit Obligation as of December 31,	$ 363.6	$ 470.7	$ 88.9	$ 104.9
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 524.8	$ 543.1	$ 220.0	$ 213.0
Actual Gain (Loss) on Plan Assets	(84.8)	21.1	(43.1)	16.1
Company Contributions	0.1	—	—	—
Participant Contributions	—	—	4.8	4.5
Benefit Payments	(33.7)	(39.4)	(15.5)	(13.6)
Fair Value of Plan Assets as of December 31,	$ 406.4	$ 524.8	$ 166.2	$ 220.0
Funded Status as of December 31,	$ 42.8	$ 54.1	$ 77.3	$ 115.1

	Pension Plans		OPEB	
	December 31,			
OPCo	2022	2021	2022	2021
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 43.1	$ 54.8	$ 77.3	$ 115.1
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.3)	(0.7)	—	—
Funded Status	$ 42.8	$ 54.1	$ 77.3	$ 115.1

PSO	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 252.6	$ 279.9	$ 54.4	$ 64.0
Service Cost	7.4	8.0	0.4	0.6
Interest Cost	7.0	6.7	1.5	1.6
Actuarial Gain	(52.9)	(17.2)	(5.2)	(6.8)
Plan Amendments	—	—	—	(0.3)
Benefit Payments	(21.8)	(24.8)	(7.9)	(7.0)
Participant Contributions	—	—	2.5	2.3
Benefit Obligation as of December 31,	$ 192.3	$ 252.6	$ 45.7	$ 54.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 286.2	$ 299.8	$ 114.0	$ 107.8
Actual Gain (Loss) on Plan Assets	(46.0)	11.1	(23.2)	10.9
Company Contributions	0.1	0.1	—	—
Participant Contributions	—	—	2.5	2.3
Benefit Payments	(21.8)	(24.8)	(7.9)	(7.0)
Fair Value of Plan Assets as of December 31,	$ 218.5	$ 286.2	$ 85.4	$ 114.0
Funded Status as of December 31,	$ 26.2	$ 33.6	$ 39.7	$ 59.6

	Pension Plans		OPEB	
	December 31,			
PSO	2022	2021	2022	2021
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 27.6	$ 35.5	$ 39.7	$ 59.6
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.1)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.3)	(1.8)	—	—
Funded Status	$ 26.2	$ 33.6	$ 39.7	$ 59.6

SWEPCo	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 317.7	$ 334.5	$ 65.2	$ 77.1
Service Cost	10.6	11.2	0.6	0.8
Interest Cost	9.1	8.5	1.8	1.9
Actuarial Gain	(57.9)	(3.5)	(6.6)	(9.2)
Plan Amendments	—	—	—	(0.4)
Benefit Payments	(28.8)	(33.0)	(8.8)	(7.6)
Participant Contributions	—	—	2.9	2.6
Benefit Obligation as of December 31,	$ 250.7	$ 317.7	$ 55.1	$ 65.2
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 308.3	$ 326.9	$ 136.6	$ 129.9
Actual Gain (Loss) on Plan Assets	(48.3)	14.3	(27.7)	11.7
Company Contributions	0.1	0.1	—	—
Participant Contributions	—	—	2.9	2.6
Benefit Payments	(28.8)	(33.0)	(8.8)	(7.6)
Fair Value of Plan Assets as of December 31,	$ 231.3	$ 308.3	$ 103.0	$ 136.6
Funded (Underfunded) Status as of December 31,	$ (19.4)	$ (9.4)	$ 47.9	$ 71.4

	Pension Plans		OPEB	
	December 31,			
SWEPCo	2022	2021	2022	2021
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 47.9	$ 71.4
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.1)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(19.3)	(9.3)	—	—
Funded (Underfunded) Status	$ (19.4)	$ (9.4)	$ 47.9	$ 71.4

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

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

AEP	**Pension Plans**		**OPEB**	
	December 31,			
	2022	**2021**	**2022**	**2021**
Components	**(in millions)**			
Net Actuarial (Gain) Loss	$ 935.6	$ 894.7	$ 300.0	$ (103.6)
Prior Service Cost (Credit)	0.2	0.2	(90.5)	(161.9)
Recorded as				
Regulatory Assets	$ 841.8	$ 878.0	$ 126.0	$ (195.1)
Deferred Income Taxes	19.9	3.6	17.5	(14.7)
Net of Tax AOCI	74.1	13.3	66.0	(55.7)

AEP	**Pension Plans**		**OPEB**	
	2022	**2021**	**2022**	**2021**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 103.9	$ (183.4)	$ 403.6	$ (205.5)
Amortization of Actuarial Loss	(63.0)	(101.5)	—	—
Prior Service Credit	—	—	—	(5.5)
Amortization of Prior Service Credit	—	—	71.4	70.9
Change for the Year Ended December 31,	$ 40.9	$ (284.9)	$ 475.0	$ (140.1)

AEP Texas	**Pension Plans**		**OPEB**	
	December 31,			
	2022	**2021**	**2022**	**2021**
Components	**(in millions)**			
Net Actuarial (Gain) Loss	$ 161.9	$ 144.7	$ 29.7	$ (5.2)
Prior Service Credit	—	—	(7.6)	(13.7)
Recorded as				
Regulatory Assets	$ 151.2	$ 136.7	$ 22.0	$ (17.7)
Deferred Income Taxes	2.4	1.8	0.1	(0.2)
Net of Tax AOCI	8.3	6.2	—	(1.0)

AEP Texas	**Pension Plans**		**OPEB**	
	2022	**2021**	**2022**	**2021**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 22.4	$ (7.5)	$ 34.9	$ (17.5)
Amortization of Actuarial Loss	(5.2)	(8.3)	—	—
Prior Service Credit	—	—	—	(0.4)
Amortization of Prior Service Credit	—	—	6.1	6.0
Change for the Year Ended December 31,	$ 17.2	$ (15.8)	$ 41.0	$ (11.9)

APCo

Components	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
	December 31,			
	(in millions)			
Net Actuarial (Gain) Loss	$ 95.6	$ 83.9	$ 40.5	$ (18.9)
Prior Service Credit	—	—	(13.4)	(23.8)
Recorded as				
Regulatory Assets	$ 93.6	$ 82.5	$ 14.7	$ (19.8)
Deferred Income Taxes	0.4	0.3	2.5	(4.9)
Net of Tax AOCI	1.6	1.1	9.9	(18.0)

APCo

Components	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 19.1	$ (30.4)	$ 59.4	$ (30.0)
Amortization of Actuarial Loss	(7.4)	(12.0)	—	—
Prior Service Credit	—	—	—	(0.9)
Amortization of Prior Service Credit	—	—	10.4	10.3
Change for the Year Ended December 31,	$ 11.7	$ (42.4)	$ 69.8	$ (20.6)

I&M

Components	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
	December 31,			
	(in millions)			
Net Actuarial (Gain) Loss	$ (6.9)	$ (1.6)	$ 40.2	$ (10.7)
Prior Service Credit	—	—	(12.4)	(22.1)
Recorded as				
Regulatory Assets/Liabilities (a)	$ 4.8	$ 3.1	$ 22.1	$ (30.7)
Deferred Income Taxes	(2.4)	(1.0)	1.2	(0.4)
Net of Tax AOCI	(9.3)	(3.7)	4.5	(1.7)

(a) Recorded as a Regulatory Asset as of December 31, 2022 and recorded as a Regulatory Liability as of December 31, 2021.

I&M

Components	Pension Plans 2022	Pension Plans 2021	OPEB 2022	OPEB 2021
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 1.8	$ (29.4)	$ 50.9	$ (26.3)
Amortization of Actuarial Loss	(7.1)	(11.7)	—	—
Prior Service Credit	—	—	—	(0.7)
Amortization of Prior Service Credit	—	—	9.7	9.6
Change for the Year Ended December 31,	$ (5.3)	$ (41.1)	$ 60.6	$ (17.4)

OPCo	Pension Plans		OPEB	
	December 31,			
	2022	2021	2022	2021
Components	(in millions)			
Net Actuarial (Gain) Loss	$ 124.3	$ 118.1	$ 27.6	$ (18.5)
Prior Service Credit	—	—	(9.2)	(16.3)
Recorded as				
Regulatory Assets	$ 124.3	$ 118.1	$ 18.4	$ (34.8)

OPCo	Pension Plans		OPEB	
	2022	2021	2022	2021
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 11.7	$ (22.8)	$ 46.1	$ (22.1)
Amortization of Actuarial Loss	(5.5)	(9.1)	—	—
Prior Service Credit	—	—	—	(0.6)
Amortization of Prior Service Credit	—	—	7.1	7.2
Change for the Year Ended December 31,	$ 6.2	$ (31.9)	$ 53.2	$ (15.5)

PSO	Pension Plans		OPEB	
	December 31,			
	2022	2021	2022	2021
Components	(in millions)			
Net Actuarial (Gain) Loss	$ 38.8	$ 35.0	$ 22.0	$ (2.1)
Prior Service Credit	—	—	(5.6)	(10.0)
Recorded as				
Regulatory Assets	$ 38.8	$ 35.0	$ 16.4	$ (12.1)

PSO	Pension Plans		OPEB	
	2022	2021	2022	2021
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 6.7	$ (16.0)	$ 24.1	$ (12.6)
Amortization of Actuarial Loss	(2.9)	(4.9)	—	—
Prior Service Credit	—	—	—	(0.3)
Amortization of Prior Service Credit	—	—	4.4	4.4
Change for the Year Ended December 31,	$ 3.8	$ (20.9)	$ 28.5	$ (8.5)

SWEPCo	Pension Plans		OPEB	
	December 31,			
	2022	2021	2022	2021
Components	(in millions)			
Net Actuarial (Gain) Loss	$ 77.6	$ 76.4	$ 25.0	$ (3.5)
Prior Service Credit	—	—	(7.0)	(12.3)
Recorded as				
Regulatory Assets	$ 77.6	$ 76.4	$ 11.2	$ (8.9)
Deferred Income Taxes	—	—	1.5	(1.4)
Net of Tax AOCI	—	—	5.3	(5.5)

SWEPCo	Pension Plans		OPEB	
	2022	2021	2022	2021
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 5.0	$ (4.3)	$ 28.5	$ (15.0)
Amortization of Actuarial Loss	(3.8)	(6.2)	—	—
Prior Service Credit	—	—	—	(0.4)
Amortization of Prior Service Credit	—	—	5.3	5.3
Change for the Year Ended December 31,	$ 1.2	$ (10.5)	$ 33.8	$ (10.1)

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	2022	2021	2022	2021
AEP Texas	8.1 %	8.3 %	8.3 %	8.3 %
APCo	12.9 %	12.8 %	14.8 %	14.8 %
I&M	12.9 %	12.7 %	12.3 %	12.2 %
OPCo	9.9 %	9.8 %	10.7 %	10.8 %
PSO	5.3 %	5.3 %	5.5 %	5.6 %
SWEPCo	5.6 %	5.8 %	6.6 %	6.7 %

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.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2021:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 388.9	$ —	$ —	$ —	$ 388.9	7.2 %
International	465.7	—	—	—	465.7	8.7 %
Common Collective Trusts (b)	—	—	—	463.9	463.9	8.7 %
Subtotal – Equities	854.6	—	—	463.9	1,318.5	24.6 %
Fixed Income (a):						
United States Government and Agency Securities	0.1	1,557.6	—	—	1,557.7	29.1 %
Corporate Debt	—	1,295.9	—	—	1,295.9	24.2 %
Foreign Debt	—	259.4	—	—	259.4	4.8 %
State and Local Government	—	57.1	—	—	57.1	1.1 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	0.1	3,171.3	—	—	3,171.4	59.2 %
Infrastructure (b)	—	—	—	92.1	92.1	1.7 %
Real Estate (b)	—	—	—	232.6	232.6	4.4 %
Alternative Investments (b)	—	—	—	448.8	448.8	8.4 %
Cash and Cash Equivalents (b)	—	64.3	—	53.4	117.7	2.2 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	(28.2)	(28.2)	(0.5)%
Total	$ 854.7	$ 3,235.6	$ —	$ 1,262.6	$ 5,352.9	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column 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, 2021:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 474.0	$ —	$ —	$ —	$ 474.0	23.2 %
International	296.3	—	—	—	296.3	14.5 %
Common Collective Trusts (a)	—	—	—	265.0	265.0	13.0 %
Subtotal – Equities	770.3	—	—	265.0	1,035.3	50.7 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	167.7	167.7	8.2 %
United States Government and Agency Securities	—	222.4	—	—	222.4	10.9 %
Corporate Debt	—	233.2	—	—	233.2	11.4 %
Foreign Debt	—	39.8	—	—	39.8	2.0 %
State and Local Government	91.9	13.6	—	—	105.5	5.1 %
Subtotal – Fixed Income	91.9	509.0	—	167.7	768.6	37.6 %
Trust Owned Life Insurance:						
International Equities	—	23.4	—	—	23.4	1.1 %
United States Bonds	—	171.3	—	—	171.3	8.4 %
Subtotal – Trust Owned Life Insurance	—	194.7	—	—	194.7	9.5 %
Cash and Cash Equivalents (a)	33.0	—	—	6.7	39.7	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	6.0	6.0	0.3 %
Total	$ 895.2	$ 703.7	$ —	$ 445.4	$ 2,044.3	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	$ 3,827.4	$ 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

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,822.5	$ 391.4	$ 597.0	$ 575.2	$ 440.0	$ 232.1	$ 291.4
Nonqualified Pension Plans	69.7	3.3	0.4	1.2	0.3	1.5	1.3
Total as of December 31, 2021	$ 4,892.2	$ 394.7	$ 597.4	$ 576.4	$ 440.3	$ 233.6	$ 292.7

Obligations in Excess of Fair Values

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

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 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)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 78.4	$ 3.6	$ 0.8	$ 1.9	$ 0.7	$ 1.9	$ 317.7
Fair Value of Plan Assets	—	—	—	—	—	—	308.3
Underfunded Projected Benefit Obligation as of December 31, 2021	$ (78.4)	$ (3.6)	$ (0.8)	$ (1.9)	$ (0.7)	$ (1.9)	$ (9.4)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
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)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 69.7	$ 3.3	$ 0.4	$ 1.2	$ 0.3	$ 1.5	$ 1.3
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2021	$ (69.7)	$ (3.3)	$ (0.4)	$ (1.2)	$ (0.3)	$ (1.5)	$ (1.3)

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 2023:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 6.3	$ 3.1
AEP Texas	0.4	0.1
APCo	—	1.6
I&M	0.1	—
PSO	0.1	—
SWEPCo	0.1	—

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

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2023	$ 369.0	$ 35.4	$ 43.7	$ 38.1	$ 32.3	$ 19.2	$ 24.2
2024	373.6	36.3	43.6	39.8	31.9	18.9	25.1
2025	368.8	35.2	42.5	40.7	32.4	19.0	25.3
2026	369.6	35.0	43.0	40.4	32.0	19.2	25.5
2027	364.3	32.6	41.8	41.0	31.6	18.4	25.4
Years 2028 to 2032, in Total	1,702.3	138.9	202.1	196.4	146.0	81.1	107.9

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2023	$ 116.0	$ 9.1	$ 19.0	$ 14.9	$ 12.6	$ 6.7	$ 7.5
2024	117.6	9.5	19.3	15.0	12.6	6.9	7.8
2025	126.9	10.4	20.5	16.1	13.5	7.4	8.5
2026	127.4	10.6	20.4	16.3	13.4	7.3	8.6
2027	126.8	10.6	20.3	16.1	13.3	7.1	8.5
Years 2028 to 2032, in Total	604.0	48.5	95.8	75.1	62.3	32.2	41.2

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2023	$ 0.2	$ —	$ 0.1	$ —	$ —	$ —	$ —
2024	0.3	—	0.1	—	—	—	—
2025	0.3	—	0.1	—	—	—	—
2026	0.3	—	0.1	—	—	—	—
2027	0.3	—	0.1	—	—	—	—
Years 2028 to 2032, in Total	1.6	—	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:

AEP	Pension Plans			OPEB		
	Years Ended December 31,					
	2022	2021	2020	2022	2021	2020
	(in millions)					
Service Cost	$ 123.1	$ 129.2	$ 111.9	$ 7.4	$ 9.5	$ 10.0
Interest Cost	148.2	137.2	167.9	29.2	30.5	39.8
Expected Return on Plan Assets	(253.4)	(229.7)	(264.9)	(110.0)	(91.1)	(95.6)
Amortization of Prior Service Credit	—	—	—	(71.4)	(70.9)	(69.8)
Amortization of Net Actuarial Loss	63.0	101.5	93.7	—	—	5.9
Settlements	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	80.9	138.2	108.6	(144.8)	(122.0)	(109.7)
Capitalized Portion	(53.8)	(55.7)	(47.0)	(3.2)	(4.1)	(4.2)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 27.1	$ 82.5	$ 61.6	$ (148.0)	$ (126.1)	$ (113.9)

AEP Texas

	Pension Plans			OPEB		
	Years Ended December 31,					
	2022	2021	2020	2022	2021	2020
	(in millions)					
Service Cost	$ 11.1	$ 11.8	$ 10.0	$ 0.5	$ 0.7	$ 0.8
Interest Cost	12.1	11.2	13.9	2.2	2.4	3.2
Expected Return on Plan Assets	(21.0)	(19.5)	(22.7)	(9.1)	(7.5)	(8.0)
Amortization of Prior Service Credit	—	—	—	(6.1)	(6.0)	(5.9)
Amortization of Net Actuarial Loss	5.2	8.3	7.8	—	—	0.5
Net Periodic Benefit Cost (Credit)	7.4	11.8	9.0	(12.5)	(10.4)	(9.4)
Capitalized Portion	(6.2)	(6.6)	(5.5)	(0.3)	(0.4)	(0.4)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1.2	$ 5.2	$ 3.5	$ (12.8)	$ (10.8)	$ (9.8)

APCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2022	2021	2020	2022	2021	2020
	(in millions)					
Service Cost	$ 11.4	$ 11.9	$ 10.5	$ 0.8	$ 1.0	$ 1.0
Interest Cost	17.5	16.4	20.3	4.7	4.9	6.6
Expected Return on Plan Assets	(32.3)	(29.1)	(33.6)	(16.3)	(13.5)	(14.4)
Amortization of Prior Service Credit	—	—	—	(10.4)	(10.3)	(10.2)
Amortization of Net Actuarial Loss	7.4	12.0	11.2	—	—	0.9
Net Periodic Benefit Cost (Credit)	4.0	11.2	8.4	(21.2)	(17.9)	(16.1)
Capitalized Portion	(5.0)	(5.2)	(4.5)	(0.4)	(0.4)	(0.4)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (1.0)	$ 6.0	$ 3.9	$ (21.6)	$ (18.3)	$ (16.5)

I&M

	Pension Plans			OPEB		
	Years Ended December 31,					
	2022	2021	2020	2022	2021	2020
	(in millions)					
Service Cost	$ 16.2	$ 17.5	$ 15.4	$ 0.9	$ 1.3	$ 1.4
Interest Cost	17.0	16.2	19.7	3.4	3.5	4.7
Expected Return on Plan Assets	(32.4)	(28.9)	(33.3)	(13.7)	(11.1)	(11.7)
Amortization of Prior Service Credit	—	—	—	(9.7)	(9.6)	(9.5)
Amortization of Net Actuarial Loss	7.1	11.7	10.8	—	—	0.7
Net Periodic Benefit Cost (Credit)	7.9	16.5	12.6	(19.1)	(15.9)	(14.4)
Capitalized Portion	(4.6)	(4.9)	(4.3)	(0.3)	(0.4)	(0.4)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.3	$ 11.6	$ 8.3	$ (19.4)	$ (16.3)	$ (14.8)

OPCo	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
	(in millions)					
Service Cost	$ 11.2	$ 11.4	$ 9.7	$ 0.6	$ 0.8	$ 0.9
Interest Cost	13.3	12.5	15.4	3.0	3.0	4.2
Expected Return on Plan Assets	(24.8)	(22.3)	(26.3)	(12.0)	(9.7)	(10.5)
Amortization of Prior Service Credit	—	—	—	(7.1)	(7.2)	(7.0)
Amortization of Net Actuarial Loss	5.5	9.1	8.5	—	—	0.7
Net Periodic Benefit Cost (Credit)	5.2	10.7	7.3	(15.5)	(13.1)	(11.7)
Capitalized Portion	(6.1)	(6.2)	(5.0)	(0.3)	(0.4)	(0.5)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (0.9)	$ 4.5	$ 2.3	$ (15.8)	$ (13.5)	$ (12.2)

PSO	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
	(in millions)					
Service Cost	$ 7.4	$ 8.0	$ 7.3	$ 0.4	$ 0.6	$ 0.7
Interest Cost	7.0	6.7	8.5	1.5	1.6	2.1
Expected Return on Plan Assets	(13.4)	(12.3)	(14.5)	(6.1)	(5.0)	(5.2)
Amortization of Prior Service Credit	—	—	—	(4.4)	(4.4)	(4.4)
Amortization of Net Actuarial Loss	2.9	4.9	4.7	—	—	0.3
Net Periodic Benefit Cost (Credit)	3.9	7.3	6.0	(8.6)	(7.2)	(6.5)
Capitalized Portion	(3.2)	(3.4)	(2.8)	(0.2)	(0.3)	(0.3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 0.7	$ 3.9	$ 3.2	$ (8.8)	$ (7.5)	$ (6.8)

SWEPCo	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
	(in millions)					
Service Cost	$ 10.6	$ 11.2	$ 9.9	$ 0.6	$ 0.8	$ 0.8
Interest Cost	9.1	8.5	10.2	1.8	1.9	2.5
Expected Return on Plan Assets	(14.6)	(13.5)	(15.7)	(7.3)	(6.1)	(6.3)
Amortization of Prior Service Credit	—	—	—	(5.3)	(5.3)	(5.2)
Amortization of Net Actuarial Loss	3.8	6.2	5.7	—	—	0.4
Net Periodic Benefit Cost (Credit)	8.9	12.4	10.1	(10.2)	(8.7)	(7.8)
Capitalized Portion	(4.0)	(4.1)	(3.4)	(0.2)	(0.3)	(0.3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 4.9	$ 8.3	$ 6.7	$ (10.4)	$ (9.0)	$ (8.1)

American Electric Power System Retirement Savings Plan

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

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

Company	Year Ended December 31, 2022	2021	2020
		(in millions)	
AEP	$ 81.9	$ 79.9	$ 81.8
AEP Texas	6.5	6.4	6.4
APCo	7.8	7.6	7.7
I&M	11.1	10.9	11.3
OPCo	7.7	7.2	7.3
PSO	4.7	4.6	4.9
SWEPCo	6.4	6.4	6.7

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, 2022 and was in Critical Status for the plan year beginning July 1, 2021. As required under the PPA, the Plan adopted a Rehabilitation Plan in 2015. The Rehabilitation Plan has been updated annually, most recently in April 2022.

The amount contributed in 2022 was $329 thousand and represented 12.5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2021. The amounts contributed in 2021 and 2020 were immaterial and represented less than 5% of the total contributions in the plan years ended June 30, 2020 and June 30, 2019. The contributions in 2022, 2021 and 2020 did not include surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the March 31, 2023 expiration of the current collective bargaining agreement between the Cook Coal Terminal (CCT) facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

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, 2022 and 2021, the liability balance was $12 million and $22 million, respectively. AEP recovers the estimated value of its UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. As of December 31, 2022 and 2021, AEP recorded a regulatory asset on the balance sheets for $0 and $1 million, respectively. 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 renewable energy investments and management services.
- Marketing, risk management and retail activities in ERCOT, MISO, PJM and SPP.
- Competitive generation in PJM.

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

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2022, 2021 and 2020 and reportable segment balance sheet information as of December 31, 2022 and 2021.

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)	—
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 (d)	$ 49,761.8	$ 22,920.2	$ 15,215.8	$ 4,520.1	$ 6,834.5 (b)	$ (5,783.0) (c)	$ 93,469.4
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)	—
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
Total Assets (d)	$ 46,974.2	$ 21,120.2	$ 13,873.3	$ 4,263.6	$ 5,846.5 (b)	$ (4,409.1) (c)	$ 87,668.7
Investments in Equity Method Investees	$ 33.5	$ 2.5	$ 830.4	$ 487.8	$ 93.3	$ —	$ 1,447.5

2020	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 8,753.2	$ 4,238.7	$ 297.4	$ 1,621.0	$ 8.2	$ —	$ 14,918.5
Other Operating Segments	126.2	107.2	901.4	104.6	88.6	(1,328.0)	—
Total Revenues	$ 8,879.4	$ 4,345.9	$ 1,198.8	$ 1,725.6	$ 96.8	$ (1,328.0)	$ 14,918.5
Depreciation and Amortization	$ 1,600.5	$ 751.1	$ 257.6	$ 72.8	$ 0.8	$ —	$ 2,682.8
Interest Expense	565.0	289.2	133.2	24.0	196.4	(42.1)	1,165.7
Income Tax Expense (Benefit)	(7.0)	29.7	130.8	(108.0)	(5.0)	—	40.5
Equity Earnings of Unconsolidated Subsidiaries	2.9	—	82.4	3.2	2.6	—	91.1
Net Income (Loss)	$ 1,064.5	$ 496.4	$ 508.5	$ 216.9	$ (89.6)	$ —	$ 2,196.7
Gross Property Additions	$ 2,291.2	$ 2,108.1	$ 1,649.3	$ 197.0	$ 16.0	$ (15.3)	$ 6,246.3
Investments in Equity Method Investees	$ 37.1	$ 2.1	$ 831.3	$ 467.0	$ 68.8	$ —	$ 1,406.3

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and other nonallocated costs.
(b) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(c) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.
(d) Amount includes Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the years ended December 31, 2022, 2021 and 2020 and reportable segment balance sheet information as of December 31, 2022 and 2021.

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 (e)	$ 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
Total Assets (e)	$ 12,564.3	$ 4,389.5 (c)	$ (4,429.4) (d)	$ 12,524.4

2020	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 248.8	$ —	$ —	$ 248.8
Sales to AEP Affiliates	896.3	—	—	896.3
Other Revenue	0.6	—	—	0.6
Total Revenues	$ 1,145.7	$ —	$ —	$ 1,145.7
Depreciation and Amortization	$ 249.0	$ —	$ —	$ 249.0
Interest Income	0.9	149.6	(148.1) (a)	2.4
Allowance for Equity Funds Used During Construction	74.0	—	—	74.0
Interest Expense	127.8	148.1	(148.1) (a)	127.8
Income Tax Expense	106.5	0.2	—	106.7
Net Income	$ 422.3	$ 1.1 (b)	$ —	$ 423.4
Gross Property Additions	$ 1,621.9	$ —	$ —	$ 1,621.9

(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.
(e) Amount includes Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

10. DERIVATIVES AND HEDGING

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

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 tables represent the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments
December 31, 2022

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	226.8	—	17.9	4.2	2.5	2.9	2.2
Natural Gas	MMBtus	77.1	—	1.9	—	—	1.9	2.1
Heating Oil and Gasoline	Gallons	6.9	1.9	1.0	0.7	1.4	0.9	1.0
Interest Rate	USD	$ 99.9	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,650.0	$ —	$ —	$ —	$ —	$ 200.0	$ —

December 31, 2021

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	287.9	—	33.1	13.6	2.7	11.9	3.4
Natural Gas	MMBtus	34.1	—	—	—	—	1.3	5.1
Heating Oil and Gasoline	Gallons	7.4	1.9	1.1	0.7	1.5	0.8	1.0
Interest Rate	USD	$ 116.5	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 950.0	$ —	$ —	$ —	$ —	$ —	$ —

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 $481 million and $263 million as of December 31, 2022 and 2021, respectively. The amount of cash collateral from third-parties netted against short-term and long-term risk management assets were immaterial for the Registrant Subsidiaries as of December 31, 2022 and 2021. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities were immaterial for the Registrants as of December 31, 2022 and 2021.

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets. 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.

AEP

	December 31, 2022					
	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)			
	(in millions)					
Current Risk Management Assets (d)	$ 956.9	$ 212.2	$ 1.8	$ 1,170.9	$ (830.5)	$ 340.4
Long-term Risk Management Assets	565.5	148.9	14.3	728.7	(444.6)	284.1
Total Assets	1,522.4	361.1	16.1	1,899.6	(1,275.1)	624.5
Current Risk Management Liabilities (e)	663.7	60.4	41.4	765.5	(620.3)	145.2
Long-term Risk Management Liabilities	412.0	17.4	91.1	520.5	(175.2)	345.3
Total Liabilities	1,075.7	77.8	132.5	1,286.0	(795.5)	490.5
Total MTM Derivative Contract Net Assets (Liabilities) (f)	$ 446.7	$ 283.3	$ (116.4)	$ 613.6	$ (479.6)	$ 134.0

	December 31, 2021					
	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)			
	(in millions)					
Current Risk Management Assets (d)	$ 513.4	$ 176.0	$ 1.2	$ 690.6	$ (496.2)	$ 194.4
Long-term Risk Management Assets	370.5	89.1	—	459.6	(192.6)	267.0
Total Assets	883.9	265.1	1.2	1,150.2	(688.8)	461.4
Current Risk Management Liabilities (e)	395.7	40.9	—	436.6	(361.2)	75.4
Long-term Risk Management Liabilities	243.9	16.7	38.1	298.7	(68.4)	230.3
Total Liabilities	639.6	57.6	38.1	735.3	(429.6)	305.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 244.3	$ 207.5	$ (36.9)	$ 414.9	$ (259.2)	$ 155.7

AEP Texas

Balance Sheet Location	December 31, 2022 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ —	$ —	$ —

Balance Sheet Location	December 31, 2021 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.6	$ (0.6)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	(0.6)	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.6	$ (0.6)	$ —

APCo

Balance Sheet Location	December 31, 2022 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 69.3	$ (0.2)	$ 69.1
Long-term Risk Management Assets	0.7	(0.7)	—
Total Assets	70.0	(0.9)	69.1
Current Risk Management Liabilities	4.1	(0.5)	3.6
Long-term Risk Management Liabilities	0.7	(0.6)	0.1
Total Liabilities	4.8	(1.1)	3.7
Total MTM Derivative Contract Net Assets (f)	$ 65.2	$ 0.2	$ 65.4

Balance Sheet Location	December 31, 2021 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 47.5	$ (5.5)	$ 42.0
Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	47.7	(5.7)	42.0
Current Risk Management Liabilities	7.2	(6.4)	0.8
Long-term Risk Management Liabilities	0.2	(0.2)	—
Total Liabilities	7.4	(6.6)	0.8
Total MTM Derivative Contract Net Assets	$ 40.3	$ 0.9	$ 41.2

I&M

Balance Sheet Location	December 31, 2022 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 16.0	$ (0.8)	$ 15.2
Long-term Risk Management Assets	0.5	(0.3)	0.2
Total Assets	16.5	(1.1)	15.4
Current Risk Management Liabilities	0.9	(0.9)	—
Long-term Risk Management Liabilities	0.3	(0.3)	—
Total Liabilities	1.2	(1.2)	—
Total MTM Derivative Contract Net Assets (f)	$ 15.3	$ 0.1	$ 15.4

Balance Sheet Location	December 31, 2021 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 11.1	$ (7.8)	$ 3.3
Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	11.3	(8.0)	3.3
Current Risk Management Liabilities	14.8	(9.8)	5.0
Long-term Risk Management Liabilities	0.2	(0.2)	—
Total Liabilities	15.0	(10.0)	5.0
Total MTM Derivative Contract Net Assets (Liabilities)	$ (3.7)	$ 2.0	$ (1.7)

OPCo

Balance Sheet Location	December 31, 2022 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	2.1	(0.3)	1.8
Long-term Risk Management Liabilities	37.9	—	37.9
Total Liabilities	40.0	(0.3)	39.7
Total MTM Derivative Net Assets (Liabilities) (f)	$ (40.0)	$ 0.3	$ (39.7)

Balance Sheet Location	December 31, 2021 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.5	$ (0.5)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	(0.5)	—
Current Risk Management Liabilities	6.7	—	6.7
Long-term Risk Management Liabilities	85.8	—	85.8
Total Liabilities	92.5	—	92.5
Total MTM Derivative Contract Net Liabilities	$ (92.0)	$ (0.5)	$ (92.5)

PSO

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	December 31, 2022				
			(in millions)		
Current Risk Management Assets	$ 24.1	$ 1.6	$ 25.7	$ (0.4)	$ 25.3
Long-term Risk Management Assets	—	—	—	—	—
Total Assets	24.1	1.6	25.7	(0.4)	25.3
Current Risk Management Liabilities	2.1	—	2.1	(0.5)	1.6
Long-term Risk Management Liabilities	—	—	—	—	—
Total Liabilities	2.1	—	2.1	(0.5)	1.6
Total MTM Derivative Contract Net Assets (f)	$ 22.0	$ 1.6	$ 23.6	$ 0.1	$ 23.7

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	December 31, 2021		
		(in millions)	
Current Risk Management Assets	$ 12.4	$ (0.3)	$ 12.1
Long-term Risk Management Assets	—	—	—
Total Assets	12.4	(0.3)	12.1
Current Risk Management Liabilities	3.7	—	3.7
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	3.7	—	3.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 8.7	$ (0.3)	$ 8.4

SWEPCo

Balance Sheet Location	December 31, 2022 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 16.8	$ (0.4)	$ 16.4
Long-term Risk Management Assets	—	—	—
Total Assets	16.8	(0.4)	16.4
Current Risk Management Liabilities	2.0	(0.6)	1.4
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	2.0	(0.6)	1.4
Total MTM Derivative Contract Net Assets (f)	$ 14.8	$ 0.2	$ 15.0

Balance Sheet Location	December 31, 2021 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 10.1	$ (0.3)	$ 9.8
Long-term Risk Management Assets	1.1	—	1.1
Total Assets	11.2	(0.3)	10.9
Current Risk Management Liabilities	2.1	—	2.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	2.1	—	2.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 9.1	$ (0.3)	$ 8.8

(a) Derivative instruments within these categories are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.
(d) Amount excludes Risk Management Assets of $8.5 million and $6 million as of December 31, 2022 and 2021, respectively, classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(e) Amount excludes Risk Management Liabilities of $0 and $0.1 million as of December 31, 2022 and 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(f) Increase in amounts as of December 31, 2022 are primarily due to increases in commodity prices for power and natural gas and an increase in value of FTRs.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	Year Ended December 31, 2022						
				(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 for Resale	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 (b)	$ 693.7	$ 2.8	$ 88.6	$ 19.6	$ 57.8	$ 103.7	$ 77.7

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	Year Ended December 31, 2021						
				(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 for Resale	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

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	Year Ended December 31, 2020						
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.8	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	9.5	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.4	0.1	—	—	0.1
Purchased Electricity for Resale	1.4	—	1.2	0.1	—	—	—
Other Operation	(2.0)	(0.6)	(0.2)	(0.2)	(0.3)	(0.2)	(0.3)
Maintenance	(2.9)	(0.8)	(0.4)	(0.3)	(0.5)	(0.3)	(0.4)
Regulatory Assets (a)	(4.8)	—	—	(0.1)	(6.6)	—	1.4
Regulatory Liabilities (a)	114.9	0.4	20.3	12.4	12.4	39.1	20.2
Total Gain (Loss) on Risk Management Contracts	$ 116.9	$ (1.0)	$ 21.3	$ 12.0	$ 5.0	$ 38.6	$ 21.0

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

(b) Increase in amounts for the year ended December 31, 2022 are primarily due to increases in commodity prices for power and natural gas and an increase in value of FTRs.

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, 2022	December 31, 2021	December 31, 2022	December 31, 2021
	(in millions)			
Long-term Debt (a) (b)	$ (855.5)	$ (952.3)	$ 89.7	$ (8.5)

(a) Amounts included on the Balance Sheet within Current and Noncurrent Liabilities line items Long-term Debt Due within One Year and Long-term Debt, respectively.
(b) Amounts include $(38) million and $(46) million as of December 31, 2022 and 2021, 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,		
	2022	2021	2020
	(in millions)		
Gain (Loss) on Interest Rate Contracts:			
Fair Value Hedging Instruments (a)	$ (90.4)	$ (35.5)	$ 41.1
Fair Value Portion of Long-term Debt (a)	90.4	35.5	(41.1)

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

In June 2020, AEP terminated a $500 million notional amount interest rate swap resulting in the discontinuance of the hedging relationship. A gain of $57 million on the fair value of the hedging instrument was settled in cash and recorded within operating activities on the statements of cash flows. Subsequent to the discontinuation of hedge accounting, the remaining adjustment to the carrying amount of the hedged item of $57 million will be amortized on a straight line basis through November 2027 in Interest Expense on the statements of income.

Accounting for Cash Flow Hedging Strategies (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 for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2022, 2021 and 2020, AEP applied cash flow hedging to outstanding power derivatives and the Registrant Subsidiaries did not.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the years ended 2022, 2021 and 2020, AEP applied cash flow hedging to outstanding interest rate derivatives. During the years ended 2021 and 2020, APCo applied cash flow hedging to outstanding interest rate derivatives. During the year ended 2022, PSO applied cash flow hedging to outstanding interest rate derivatives. During the years ended 2022, 2021 and 2020, the other Registrant Subsidiaries did not have 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 AEP's Balance Sheets

	December 31, 2022		December 31, 2021	
	Commodity	Interest Rate	Commodity	Interest Rate
		(in millions)		
AOCI Gain (Loss) Net of Tax	$ 223.5	$ 0.3	$ 163.7	$ (21.3)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	119.9	0.3	106.7	(3.3)

As of December 31, 2022 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 99 months and 96 months for commodity and interest rate hedges, respectively.

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

	December 31, 2022		December 31, 2021	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (0.3)	$ (0.2)	$ (1.3)	$ (1.1)
APCo	6.7	0.8	7.5	0.8
I&M	(5.1)	(0.6)	(6.7)	(1.6)
PSO	1.3	0.1	—	—
SWEPCo	1.1	0.2	1.2	0.1

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 $2 million and $9 million as of December 31, 2022 and 2021, respectively. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2022 and 2021.

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 $127 million and $40 million as of December 31, 2022 and 2021, respectively. There was no cash collateral posted as of December 31, 2022 and 2021, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries had no derivative contracts with cross-acceleration provisions outstanding as of December 31, 2022 and 2021.

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 liabilities subject to cross-default provisions in a net liability position of $217 million and $76 million as of December 31, 2022 and 2021, respectively, after considering contractual netting arrangements. There was no cash collateral posted as of December 31, 2022 and 2021, respectively. If a cross-default provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries' derivative contracts with cross-default provisions outstanding as of December 31, 2022 and 2021 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,			
	2022		2021	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP (a)(b)(c)	$ 35,622.6	$ 31,767.1	$ 33,454.5	$ 37,564.7
AEP Texas	5,657.8	5,045.8	5,180.8	5,663.8
AEPTCo	4,782.8	3,940.5	4,343.9	4,968.2
APCo	5,410.5	5,079.2	4,938.9	6,037.1
I&M	3,260.8	2,929.0	3,195.0	3,748.0
OPCo	2,970.3	2,516.6	2,968.5	3,437.5
PSO	1,912.8	1,635.8	1,913.5	2,163.7
SWEPCo	3,391.6	2,870.9	3,395.2	3,792.9

(a) The fair value amounts include debt related to AEP's Equity Units and had a fair value of $877 million and $1.7 billion as of December 31, 2022 and 2021, respectively. See "Equity Units" section of Note 14 for additional information.

(b) The 2022 and 2021 book value amounts exclude Long-term Debt of $1.2 billion and $1.1 billion, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

(c) The 2022 and 2021 fair value amounts exclude Long-term Debt of $1.1 billion and $1.2 billion, respectively, related to KPCo. See "Disposition of KPCo and KTCo" section of Note 7 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, 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	15.0	19.4	—	34.4
Total Other Temporary Investments and Restricted Cash	$ 223.5	$ 19.4	$ (8.3)	$ 234.6

	December 31, 2021			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash (a)	$ 48.0	$ —	$ —	$ 48.0
Other Cash Deposits	10.0	—	—	10.0
Fixed Income Securities – Mutual Funds (b)	154.3	0.5	—	154.8
Equity Securities – Mutual Funds	19.7	35.9	—	55.6
Total Other Temporary Investments and Restricted Cash	$ 232.0	$ 36.4	$ —	$ 268.4

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

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

	Years Ended December 31,		
	2022	**2021**	**2020**
		(in millions)	
Proceeds from Investment Sales	$ 30.2	$ 15.0	$ 50.9
Purchases of Investments	18.8	26.9	41.6
Gross Realized Gains on Investment Sales	6.1	3.6	3.8
Gross Realized Losses on Investment Sales	1.3	—	0.2

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,					
	2022			2021		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 21.2	$ —	$ —	$ 84.7	$ —	$ —
Fixed Income Securities:						
United States Government	1,123.8	(3.1)	(18.8)	1,156.4	66.3	(7.9)
Corporate Debt	61.6	(7.0)	(9.6)	76.7	6.7	(2.1)
State and Local Government	3.3	0.1	(0.1)	7.3	0.4	(0.1)
Subtotal Fixed Income Securities	1,188.7	(10.0)	(28.5)	1,240.4	73.4	(10.1)
Equity Securities - Domestic (a)	2,131.3	1,477.3	—	2,541.9	1,901.3	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,341.2	$ 1,467.3	$ (28.5)	$ 3,867.0	$ 1,974.7	$ (10.1)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.5 billion and $1.9 billion and unrealized losses of $6 million and $4 million as of December 31, 2022 and 2021, respectively.

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

	Years Ended December 31,		
	2022	2021	2020
	(in millions)		
Proceeds from Investment Sales	$ 2,713.6	$ 1,886.4	$ 1,593.4
Purchases of Investments	2,765.4	1,928.2	1,637.2
Gross Realized Gains on Investment Sales	52.4	103.2	26.4
Gross Realized Losses on Investment Sales	42.6	16.5	26.1

The base cost of fixed income securities was $1.2 billion and $1.2 billion as of December 31, 2022 and 2021, respectively. The base cost of equity securities was $654 million and $641 million as of December 31, 2022 and 2021, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2022 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 365.2
After 1 year through 5 years	425.4
After 5 years through 10 years	203.0
After 10 years	195.1
Total	$ 1,188.7

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, 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)	34.4	—	—	—	34.4
Total Other Temporary Investments and Restricted Cash	225.6	—	—	9.0	234.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (d) (i)	15.0	1,197.4	305.8	(1,211.3)	306.9
Cash Flow Hedges:					
Commodity Hedges (c)	—	332.7	26.7	(52.8)	306.6
Interest Rate Hedges	—	11.0	—	—	11.0
Total Risk Management Assets	15.0	1,541.1	332.5	(1,264.1)	624.5
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	$ 2,383.2	$ 2,729.8	$ 332.5	$ (1,245.2)	$ 4,200.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d) (j)	$ 21.8	$ 870.7	$ 178.9	$ (731.6)	$ 339.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	74.4	1.7	(52.8)	23.3
Fair Value Hedges	—	127.4	—	—	127.4
Total Risk Management Liabilities	$ 21.8	$ 1,072.5	$ 180.6	$ (784.4)	$ 490.5

	December 31, 2021				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 48.0	$ —	$ —	$ —	$ 48.0
Other Cash Deposits (a)	—	—	—	10.0	10.0
Fixed Income Securities – Mutual Funds	154.8	—	—	—	154.8
Equity Securities – Mutual Funds (b)	55.6	—	—	—	55.6
Total Other Temporary Investments and Restricted Cash	258.4	—	—	10.0	268.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (f) (i)	7.4	648.5	226.3	(642.4)	239.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	242.9	19.2	(41.7)	220.4
Fair Value Hedges	—	1.2	—	—	1.2
Total Risk Management Assets	7.4	892.6	245.5	(684.1)	461.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	77.7	—	—	7.0	84.7
Fixed Income Securities:					
United States Government	—	1,156.4	—	—	1,156.4
Corporate Debt	—	76.7	—	—	76.7
State and Local Government	—	7.3	—	—	7.3
Subtotal Fixed Income Securities	—	1,240.4	—	—	1,240.4
Equity Securities – Domestic (b)	2,541.9	—	—	—	2,541.9
Total Spent Nuclear Fuel and Decommissioning Trusts	2,619.6	1,240.4	—	7.0	3,867.0
Other Investments (h)	28.8	14.9	—	—	43.7
Total Assets	$ 2,914.2	$ 2,147.9	$ 245.5	$ (667.1)	$ 4,640.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f) (j)	$ 5.3	$ 485.0	$ 147.6	$ (383.2)	$ 254.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	54.0	0.6	(41.7)	12.9
Fair Value Hedges	—	38.1	—	—	38.1
Total Risk Management Liabilities	$ 5.3	$ 577.1	$ 148.2	$ (424.9)	$ 305.7

AEP Texas

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

Assets:	Level 1	Level 2	Level 3	Other	Total
	December 31, 2021 (in millions)				
Restricted Cash for Securitized Funding	$ 30.4	$ —	$ —	$ —	$ 30.4
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.6	—	(0.6)	—
Total Assets	$ 30.4	$ 0.6	$ —	$ (0.6)	$ 30.4

APCo

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

Assets:	Level 1	Level 2	Level 3	Other	Total
	December 31, 2021 (in millions)				
Restricted Cash for Securitized Funding	$ 17.6	$ —	$ —	$ —	$ 17.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	5.8	42.0	(5.8)	42.0
Total Assets	$ 17.6	$ 5.8	$ 42.0	$ (5.8)	$ 59.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 7.2	$ 0.3	$ (6.7)	$ 0.8

I&M

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 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) (g)	$ —	$ 0.6	$ 0.7	$ (1.3)	$ —

	December 31, 2021				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.8	$ 7.6	$ (8.1)	$ 3.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	77.7	—	—	7.0	84.7
Fixed Income Securities:					
United States Government	—	1,156.4	—	—	1,156.4
Corporate Debt	—	76.7	—	—	76.7
State and Local Government	—	7.3	—	—	7.3
Subtotal Fixed Income Securities	—	1,240.4	—	—	1,240.4
Equity Securities - Domestic (b)	2,541.9	—	—	—	2,541.9
Total Spent Nuclear Fuel and Decommissioning Trusts	2,619.6	1,240.4	—	7.0	3,867.0
Total Assets	$ 2,619.6	$ 1,244.2	$ 7.6	$ (1.1)	$ 3,870.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 6.7	$ 8.3	$ (10.0)	$ 5.0

OPCo

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

Assets:	December 31, 2021 Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ —	$ (0.5)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 92.5	$ —	$ 92.5

PSO

Assets:	December 31, 2022 Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 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) (g)	$ —	$ 1.7	$ 0.3	$ (0.4)	$ 1.6

Assets:	December 31, 2021 Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 12.2	$ (0.4)	$ 12.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.7	$ 0.1	$ (0.1)	$ 3.7

SWEPCo

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

	December 31, 2021				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 11.0	$ (0.4)	$ 10.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.1	$ 0.1	$ (0.1)	$ 2.1

(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, 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.
(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, 2021 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $1 million in 2022 and $1 million in periods 2023-2025; Level 2 matures $42 million in 2022, $109 million in periods 2023-2025; $10 million in periods 2026-2027 and $3 million in periods 2028-2033; Level 3 matures $82 million in 2022, $10 million in periods 2023-2025, $9 million in periods 2026-2027 and $(17) million in periods 2028-2033. Risk management commodity contracts are substantially comprised of power contracts.
(g) Substantially comprised of power contracts for the Registrant Subsidiaries.
(h) See "Warrants Held in Investee" section of Note 10 in the 2021 Annual Report for additional information.
(i) Amounts exclude Risk Management Assets of $8.5 million and $6 million as of December 31, 2022 and 2021, respectively, classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(j) Amounts exclude Risk Management Liabilities of $0 million and $0.1 million as of December 31, 2022 and 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2022	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2021	$ 97.3	$ 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
Assets and Liabilities Held for Sale related to KPCo (g)	(2.7)	—	—	—	—	—
Balance as of December 31, 2022	$ 151.9	$ 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
Assets and Liabilities Held for Sale related to KPCo (g)	(5.8)	—	—	—	—	—
Balance as of December 31, 2021	$ 97.3	$ 41.7	$ (0.7)	$ (92.5)	$ 12.1	$ 10.9

Year Ended December 31, 2020	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	39.5	13.2	2.5	(1.6)	11.9	2.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	35.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	13.8	—	—	—	—	—
Settlements	(113.1)	(51.6)	(8.6)	8.9	(27.6)	(6.6)
Transfers into Level 3 (d) (e)	(3.8)	—	—	—	—	—
Transfers out of Level 3 (e)	5.6	0.7	0.4	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	26.1	19.3	2.0	(14.0)	10.2	4.0
Balance as of December 31, 2020	$ 113.3	$ 19.3	$ 2.1	$ (110.3)	$ 10.3	$ 1.6

(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.
(g) Amounts represents Risk Management Assets classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

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The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

AEP

December 31, 2022

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 204.0	$ 167.4	Discounted Cash Flow	Forward Market Price (a)	$ 2.91	$187.34	$ 49.14
FTRs (d) (e)	128.5	13.2	Discounted Cash Flow	Forward Market Price (a)	(36.45)	20.72	1.18
Total	$ 332.5	$ 180.6					

December 31, 2021

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts (f)	$ 164.4	$ 135.2	Discounted Cash Flow	Forward Market Price (a)	$ 10.30	$ 76.70	$ 37.11
Natural Gas Contracts	3.6	—	Discounted Cash Flow	Forward Market Price (b)	3.11	4.02	3.47
FTRs (d) (e)	77.5	13.0	Discounted Cash Flow	Forward Market Price (a)	(23.93)	26.38	0.86
Total	$ 245.5	$ 148.2					

APCo

December 31, 2022							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 69.4	$ 0.3	Discounted Cash Flow	Forward Market Price	$ (2.82)	$ 18.88	$ 3.89

December 31, 2021							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 32.20	$ 56.54	$ 44.77
FTRs	42.0	—	Discounted Cash Flow	Forward Market Price	(0.30)	26.38	2.63
Total	$ 42.0	$ 0.3					

I&M

December 31, 2022							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 5.3	$ 0.7	Discounted Cash Flow	Forward Market Price	$ 0.16	$ 18.79	$ 1.23

December 31, 2021							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 32.20	$ 56.54	$ 44.77
FTRs	7.6	8.1	Discounted Cash Flow	Forward Market Price	(5.45)	17.78	(0.12)
Total	$ 7.6	$ 8.3					

OPCo

	December 31, 2022						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 40.0	Discounted Cash Flow	Forward Market Price	$ 2.91	$ 187.34	$ 48.76

	December 31, 2021						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 92.5	Discounted Cash Flow	Forward Market Price	$ 14.26	$ 52.98	$ 30.68

PSO

	December 31, 2022						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 24.0	$ 0.3	Discounted Cash Flow	Forward Market Price	$ (36.45)	$ 3.40	$ (7.55)

	December 31, 2021						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 12.2	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (18.39)	$ 1.87	$ (2.57)

SWEPCo

	December 31, 2022						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 14.6	$ 0.4	Discounted Cash Flow	Forward Market Price	$ (36.45)	$ 3.40	$ (7.55)

	December 31, 2021						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ 3.6	$ —	Discounted Cash Flow	Forward Market Price (b)	$ 3.11	$ 4.02	$ 3.47
FTRs	7.4	0.1	Discounted Cash Flow	Forward Market Price (a)	(18.39)	1.87	(2.57)
Total	$ 11.0	$ 0.1					

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.
(c) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.
(d) Amounts exclude Risk Management Assets as of December 31, 2022 and 2021 of $8.6 million and $6 million, respectively, classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(e) Amounts exclude Risk Management Liabilities as of December 31, 2022 and 2021 of $0.1 million and $0.5 million, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.
(f) Amount excludes Risk Management Liabilities of $0.1 million classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

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, 2022 and 2021:

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, 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)

Year Ended December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (138.2)	$ 5.2	$ 22.2	$ 21.4	$ 11.3	$ (26.6)	$ (11.4)	$ (13.6)
Deferred	146.9	(15.4)	65.4	(27.1)	(20.6)	74.0	8.3	19.6
Total Federal	8.7	(10.2)	87.6	(5.7)	(9.3)	47.4	(3.1)	6.0
State and Local:								
Current	(16.7)	(0.1)	2.8	9.3	1.9	(5.4)	0.1	(8.2)
Deferred	48.5	(0.9)	16.3	0.7	(0.1)	3.2	8.2	11.6
Total State and Local	31.8	(1.0)	19.1	10.0	1.8	(2.2)	8.3	3.4
Income Tax Expense (Benefit)	$ 40.5	$ (11.2)	$ 106.7	$ 4.3	$ (7.5)	$ 45.2	$ 5.2	$ 9.4

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

AEP	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 2,305.6	$ 2,488.1	$ 2,196.7
Less: Equity Earnings – Dolet Hills	(1.4)	(3.4)	(2.9)
Income Tax Expense	5.4	115.5	40.5
Pretax Income	$ 2,309.6	$ 2,600.2	$ 2,234.3
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 485.0	$ 546.0	$ 469.2
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Reversal of Origination Flow-Through	17.1	25.9	26.5
Permanent - Miscellaneous	11.5	(1.3)	(9.7)
Investment Tax Credit Amortization	(14.3)	(22.0)	(18.8)
Production Tax Credits	(197.1)	(98.8)	(83.1)
State and Local Income Taxes, Net	(14.0)	39.4	25.1
Removal Costs	(26.5)	(20.0)	(18.6)
AFUDC	(29.3)	(30.6)	(32.5)
Tax Adjustments (a)	—	(55.1)	—
Tax Reform Excess ADIT Reversal	(214.5)	(255.6)	(268.2)
Federal Return to Provision	(17.4)	(1.6)	(2.6)
CARES Act	—	—	(48.0)
Other	4.9	(10.8)	1.2
Income Tax Expense	$ 5.4	$ 115.5	$ 40.5
Effective Income Tax Rate	0.2 %	4.4 %	1.8 %

(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.

AEP Texas	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 307.9	$ 289.8	$ 241.0
Income Tax Expense (Benefit)	72.6	43.1	(11.2)
Pretax Income	$ 380.5	$ 332.9	$ 229.8
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 79.9	$ 69.9	$ 48.3
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
State and Local Income Taxes, Net	1.7	2.4	(0.8)
AFUDC	(4.1)	(4.5)	(4.1)
Parent Company Loss Benefit	—	(3.2)	(4.5)
Tax Reform Excess ADIT Reversal	(5.5)	(21.3)	(47.9)
Other	0.6	(0.2)	(2.2)
Income Tax Expense (Benefit)	$ 72.6	$ 43.1	$ (11.2)
Effective Income Tax Rate	19.1 %	12.9 %	(4.9) %

AEPTCo

	Years Ended December 31,		
	2022	2021	2020
		(in millions)	
Net Income	$ 594.2	$ 591.7	$ 423.4
Income Tax Expense	169.1	144.1	106.7
Pretax Income	$ 763.3	$ 735.8	$ 530.1
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 160.3	$ 154.5	$ 111.3
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
State and Local Income Taxes, Net	19.8	19.8	15.1
AFUDC	(14.8)	(14.1)	(15.5)
Parent Company Loss Benefit	—	(18.3)	(7.0)
Other	3.8	2.2	2.8
Income Tax Expense	$ 169.1	$ 144.1	$ 106.7
Effective Income Tax Rate	22.2 %	19.6 %	20.1 %

APCo

	Years Ended December 31,		
	2022	2021	2020
		(in millions)	
Net Income	$ 394.2	$ 348.9	$ 369.7
Income Tax Expense	18.2	22.1	4.3
Pretax Income	$ 412.4	$ 371.0	$ 374.0
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 86.6	$ 77.9	$ 78.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Reversal of Origination Flow-Through	4.7	11.7	12.7
State and Local Income Taxes, Net	(5.9)	2.1	7.9
Removal Costs	(9.8)	(7.3)	(5.7)
AFUDC	(3.7)	(4.6)	(4.5)
Parent Company Loss Benefit	—	—	(6.2)
Tax Adjustments (a)	—	4.5	—
Tax Reform Excess ADIT Reversal	(50.9)	(60.5)	(72.3)
Federal Return to Provision	(2.8)	(1.6)	(7.2)
Other	—	(0.1)	1.1
Income Tax Expense	$ 18.2	$ 22.1	$ 4.3
Effective Income Tax Rate	4.4 %	6.0 %	1.1 %

(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.

I&M

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 324.7	$ 279.8	$ 284.8
Income Tax Expense (Benefit)	4.2	(10.6)	(7.5)
Pretax Income	$ 328.9	$ 269.2	$ 277.3
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 69.1	$ 56.5	$ 58.2
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Reversal of Origination Flow-Through	2.9	3.5	1.6
Investment Tax Credit Amortization	(3.1)	(6.4)	(4.5)
State and Local Income Taxes, Net	9.6	(1.3)	1.5
Removal Costs	(12.4)	(9.7)	(10.5)
AFUDC	(2.1)	(2.7)	(2.4)
Parent Company Loss Benefit	—	(2.8)	(6.4)
Tax Reform Excess ADIT Reversal	(54.0)	(46.3)	(46.8)
Federal Return to Provision	(6.2)	(0.6)	1.8
Other	0.4	(0.8)	—
Income Tax Expense (Benefit)	$ 4.2	$ (10.6)	$ (7.5)
Effective Income Tax Rate	1.3 %	(3.9) %	(2.7) %

OPCo

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 287.8	$ 253.6	$ 271.4
Equity Earnings of Unconsolidated Subsidiaries	(0.6)	—	—
Income Tax Expense	44.2	34.4	45.2
Pretax Income	$ 331.4	$ 288.0	$ 316.6
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 69.6	$ 60.5	$ 66.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Reversal of Origination Flow-Through	3.0	2.2	3.7
State and Local Income Taxes, Net	(1.6)	—	(1.7)
AFUDC	(2.9)	(2.3)	(2.6)
Tax Adjustments (a)	—	8.9	—
Tax Reform Excess ADIT Reversal	(27.5)	(32.6)	(27.2)
Federal Return to Provision	3.5	(1.2)	6.5
Other	0.1	(1.1)	—
Income Tax Expense	$ 44.2	$ 34.4	$ 45.2
Effective Income Tax Rate	13.3 %	11.9 %	14.3 %

(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.

PSO

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 167.6	$ 141.1	$ 123.0
Income Tax Expense (Benefit)	(49.2)	4.1	5.2
Pretax Income	$ 118.4	$ 145.2	$ 128.2
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 24.9	$ 30.5	$ 26.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Investment Tax Credit Amortization	(1.6)	(1.8)	(2.1)
Production Tax Credits	(47.7)	(6.0)	—
State and Local Income Taxes, Net	4.3	6.4	6.5
Parent Company Loss Benefit	—	—	(0.2)
Tax Reform Excess ADIT Reversal	(25.4)	(25.4)	(25.5)
Federal Return to Provision	(3.7)	0.7	(0.5)
Other	—	(0.3)	0.1
Income Tax Expense (Benefit)	$ (49.2)	$ 4.1	$ 5.2
Effective Income Tax Rate	(41.6) %	2.8 %	4.1 %

SWEPCo

	Years Ended December 31, 2022	2021	2020
		(in millions)	
Net Income	$ 294.3	$ 242.1	$ 183.7
Less: Equity Earnings – Dolet Hills	(1.4)	(3.4)	(2.9)
Income Tax Expense (Benefit)	(25.2)	(0.6)	9.4
Pretax Income	$ 267.7	$ 238.1	$ 190.2
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 56.2	$ 50.0	$ 39.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Reversal of Origination Flow-Through	2.3	1.8	1.9
Depletion	(4.0)	(2.7)	(3.4)
Production Tax Credits	(57.1)	(7.2)	—
State and Local Income Taxes, Net	(4.9)	(8.0)	2.7
Parent Company Loss Benefit	—	—	(5.6)
Tax Reform Excess ADIT Reversal	(14.8)	(31.1)	(21.9)
Other	(2.9)	(3.4)	(4.2)
Income Tax Expense (Benefit)	$ (25.2)	$ (0.6)	$ 9.4
Effective Income Tax Rate	(9.4) %	(0.3) %	4.9 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

<u>**AEP**</u>	**December 31, 2022**	**2021**
	(in millions)	
Deferred Tax Assets	$ 3,402.5	$ 3,277.0
Deferred Tax Liabilities	(11,895.8)	(11,479.5)
Net Deferred Tax Liabilities (a)	$ (8,493.3)	$ (8,202.5)
Property Related Temporary Differences	$ (7,531.8)	$ (7,020.3)
Amounts Due to Customers for Future Income Taxes	921.2	1,033.0
Deferred State Income Taxes	(949.9)	(1,116.7)
Securitized Assets	(98.9)	(128.8)
Regulatory Assets	(756.7)	(645.4)
Accrued Nuclear Decommissioning	(632.7)	(743.2)
Net Operating Loss Carryforward	120.7	285.7
Tax Credit Carryforward	611.5	439.8
Operating Lease Liability	143.0	114.2
Investment in Partnership	(338.9)	(392.1)
All Other, Net	19.2	(28.7)
Net Deferred Tax Liabilities (a)	$ (8,493.3)	$ (8,202.5)

(a) 2022 and 2021 excludes Net Deferred Tax Liabilities of $469.7 million and $441.6 million, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

<u>**AEP Texas**</u>	**December 31, 2022**	**2021**
	(in millions)	
Deferred Tax Assets	$ 177.0	$ 173.8
Deferred Tax Liabilities	(1,321.2)	(1,262.7)
Net Deferred Tax Liabilities	$ (1,144.2)	$ (1,088.9)
Property Related Temporary Differences	$ (1,130.7)	$ (1,060.2)
Amounts Due to Customers for Future Income Taxes	111.0	110.0
Deferred State Income Taxes	(36.6)	(32.2)
Securitized Transition Assets	(65.0)	(84.4)
Regulatory Assets	(48.9)	(45.1)
Operating Lease Liability	20.3	15.8
All Other, Net	5.7	7.2
Net Deferred Tax Liabilities	$ (1,144.2)	$ (1,088.9)

AEPTCo

	December 31, 2022	December 31, 2021
	(in millions)	
Deferred Tax Assets	$ 162.5	$ 158.8
Deferred Tax Liabilities	(1,202.9)	(1,121.7)
Net Deferred Tax Liabilities (a)	$ (1,040.4)	$ (962.9)
Property Related Temporary Differences	$ (1,065.5)	$ (997.0)
Amounts Due to Customers for Future Income Taxes	116.6	118.2
Deferred State Income Taxes	(106.0)	(94.5)
Net Operating Loss Carryforward	5.5	8.1
All Other, Net	9.0	2.3
Net Deferred Tax Liabilities (a)	$ (1,040.4)	$ (962.9)

(a) 2022 and 2021 excludes Net Deferred Tax Liabilities of $16.1 million and $15.4 million, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

APCo

	December 31, 2022	December 31, 2021
	(in millions)	
Deferred Tax Assets	$ 510.3	$ 495.1
Deferred Tax Liabilities	(2,502.5)	(2,299.8)
Net Deferred Tax Liabilities	$ (1,992.2)	$ (1,804.7)
Property Related Temporary Differences	$ (1,509.8)	$ (1,476.5)
Amounts Due to Customers for Future Income Taxes	163.0	182.1
Deferred State Income Taxes	(318.5)	(288.8)
Securitized Assets	(33.9)	(39.3)
Regulatory Assets	(301.2)	(177.0)
Operating Lease Liability	15.6	14.2
All Other, Net	(7.4)	(19.4)
Net Deferred Tax Liabilities	$ (1,992.2)	$ (1,804.7)

I&M

	December 31, 2022	December 31, 2021
	(in millions)	
Deferred Tax Assets	$ 933.7	$ 1,072.2
Deferred Tax Liabilities	(2,090.7)	(2,172.4)
Net Deferred Tax Liabilities	$ (1,157.0)	$ (1,100.2)
Property Related Temporary Differences	$ (398.0)	$ (286.2)
Amounts Due to Customers for Future Income Taxes	114.3	135.5
Deferred State Income Taxes	(227.0)	(222.0)
Regulatory Assets	(29.5)	(23.6)
Accrued Nuclear Decommissioning	(632.7)	(743.2)
Operating Lease Liability	13.6	13.5
All Other, Net	2.3	25.8
Net Deferred Tax Liabilities	$ (1,157.0)	$ (1,100.2)

OPCo

	December 31, 2022	December 31, 2021
	(in millions)	
Deferred Tax Assets	$ 218.8	$ 204.4
Deferred Tax Liabilities	(1,319.9)	(1,205.3)
Net Deferred Tax Liabilities	$ (1,101.1)	$ (1,000.9)
Property Related Temporary Differences	$ (1,133.8)	$ (1,042.0)
Amounts Due to Customers for Future Income Taxes	112.6	117.7
Deferred State Income Taxes	(59.6)	(58.8)
Regulatory Assets	(57.6)	(39.8)
Operating Lease Liability	15.5	17.2
All Other, Net	21.8	4.8
Net Deferred Tax Liabilities	$ (1,101.1)	$ (1,000.9)

PSO

	December 31, 2022	December 31, 2021
	(in millions)	
Deferred Tax Assets	$ 225.0	$ 170.0
Deferred Tax Liabilities	(1,013.6)	(952.3)
Net Deferred Tax Liabilities	$ (788.6)	$ (782.3)
Property Related Temporary Differences	$ (763.3)	$ (708.6)
Amounts Due to Customers for Future Income Taxes	96.0	111.5
Deferred State Income Taxes	(81.9)	(83.2)
Regulatory Assets	(140.2)	(228.0)
Net Operating Loss Carryforward	25.8	111.4
Tax Credit Carryforward	54.3	6.6
All Other, Net	20.7	8.0
Net Deferred Tax Liabilities	$ (788.6)	$ (782.3)

SWEPCo

	December 31, 2022	December 31, 2021
	(in millions)	
Deferred Tax Assets	$ 374.9	$ 336.4
Deferred Tax Liabilities	(1,464.6)	(1,424.0)
Net Deferred Tax Liabilities	$ (1,089.7)	$ (1,087.6)
Property Related Temporary Differences	$ (1,053.8)	$ (989.6)
Amounts Due to Customers for Future Income Taxes	146.2	154.8
Deferred State Income Taxes	(208.7)	(234.9)
Regulatory Assets	(114.1)	(101.4)
Net Operating Loss Carryforward	42.7	67.4
Tax Credit Carryforward	66.0	8.5
All Other, Net	32.0	7.6
Net Deferred Tax Liabilities	$ (1,089.7)	$ (1,087.6)

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 and 2018 tax returns to December 31, 2023, to allow time for the current IRS audit to be completed including a refund claim approval by the Congressional Joint Committee on Taxation. The statute of limitations for the 2019 return is set to naturally expire in 2023 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 two IRS proposed adjustments on the 2017 tax return, which were immaterial. The exam is nearly complete, and AEP is currently working with 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, 2022, AEP, AEPTCo, 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 (in millions)	Years of Expiration
AEP	Arkansas	$ 224.4	2023 - 2032
AEP	Colorado	82.6	NA
AEP	Illinois	52.4	2031 - 2041
AEP	Kentucky	231.3	2030 - 2037
AEP	Louisiana	586.8	NA
AEP	Michigan	58.7	2029 - 2031
AEP	New Jersey	13.7	2036 - 2040
AEP	New Mexico	22.9	NA
AEP	Ohio Municipal	1,257.7	2023 - 2027
AEP	Oklahoma	943.3	2037 - 2037
AEP	Pennsylvania	64.4	2030 - 2042
AEP	Tennessee	77.7	2030 - 2037
AEP	Virginia	11.2	2030 - 2037
AEP	West Virginia	12.3	2029 - 2037
AEPTCo	Oklahoma	33.0	2037 - 2037
OPCo	Ohio Municipal	190.1	2024 - 2027
PSO	Oklahoma	899.6	2037 - 2037
SWEPCo	Arkansas	224.2	2023 - 2032
SWEPCo	Louisiana	577.2	NA

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, 2022, 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	$ 612.0	$ 39.2
AEP Texas	1.5	—
AEPTCo	0.2	—
APCo	2.0	—
I&M	11.4	—
OPCo	1.0	—
PSO	54.3	39.2
SWEPCo	66.0	—

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, 2022, 2021 and 2020 was not material.

Uncertain Tax Positions

The reconciliations of the beginning and ending amounts of unrecognized tax benefits for AEP and OPCo are presented below. The amount and activity of unrecognized tax benefits for the other Registrant Subsidiaries was immaterial for periods presented:

	AEP		
	2022	2021	2020
		(in millions)	
Balance as of January 1,	$ 14.3	$ 13.2	$ 24.1
Increase – Tax Positions Taken During a Prior Period	5.1	1.2	0.6
Decrease – Tax Positions Taken During a Prior Period	—	(3.2)	(14.5)
Increase – Tax Positions Taken During the Current Year	3.8	3.1	3.0
Decrease – Tax Positions Taken During the Current Year	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—
Balance as of December 31,	$ 23.2	$ 14.3	$ 13.2

	OPCo		
	2022	2021	2020
		(in millions)	
Balance as of January 1,	$ —	$ 3.2	$ 8.4
Increase – Tax Positions Taken During a Prior Period	5.1	—	—
Decrease – Tax Positions Taken During a Prior Period	—	(3.2)	(5.2)
Increase – Tax Positions Taken During the Current Year	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—
Balance as of December 31,	$ 5.1	$ —	$ 3.2

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, 2022, 2021 and 2020 were $23 million, $14 million, and $12 million, respectively.

Federal Tax Legislation

In March 2020, the CARES Act was signed into law. The CARES Act includes tax relief provisions including a 5-year NOL carryback from years 2018-2020. In the third quarter of 2020, AEP requested a $95 million refund of taxes paid in 2014 under the 5-year NOL carryback provision of the CARES Act. AEP carried back a NOL generated on the 2019 Federal income tax return at a 21% federal corporate income tax rate to the 2014 Federal income tax return at a 35% corporate income tax rate. As a result of the change in the corporate income tax rates between the two periods, AEP realized a tax benefit of $48 million during the third quarter of 2020 primarily at the Generation & Marketing segment. AEP received the $95 million refund in the fourth quarter of 2021.

Inflation Reduction Act

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. This legislation has no material impact on the current period financial statements. 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 November 2022, the IRS released Notice 2022-61 addressing the Prevailing Wage and Apprenticeship Requirements (PWAR) tied to full value PTCs and ITCs for projects that begin construction on or after January 29, 2023. AEP's future renewable energy projects that begin construction after this date will be required to, and expect to, satisfy the PWAR to receive full value ITCs and PTCs.

In December 2022, the IRS released Notice 2023-7 addressing time sensitive issues related to the CAMT. The notice provided initial guidance that AEP can begin to rely on in 2023 and also stated that additional guidance is expected, of which AEP will continue to monitor and assess. 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.

The enactment of the IRA will have future cash flow and income tax reporting considerations. AEP and subsidiaries expect to be applicable corporations beginning in 2023 and AEP expects to have CAMT cash tax payments beginning in 2024. CAMT cash taxes are expected to be 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 will be presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP will present the gain or loss on sale of tax credits through income tax expense. Management believes this presentation provides consistency in financial statement reporting as it matches the originating income tax benefit of the tax credits.

State Tax Legislation

In April 2021, West Virginia enacted House Bill (HB) 2026. HB 2026 changes the state income tax apportionment formula from a ratio that includes property, payroll and sales to a single sales factor apportionment regime effective for tax years beginning on or after January 1, 2022. HB 2026 also eliminates the "throw out" rule related to sales of tangible personal property for sales factor apportionment calculation purposes and introduces a market-based sourcing for sales of services and intangible property. During 2021, AEP recorded $23 million in Income Tax Expense as a result of remeasuring West Virginia deferred taxes under the new apportionment methodology. The enacted legislation does not impact AEP Texas, PSO or SWEPCo.

In May 2021, Oklahoma enacted HB 2960. HB 2960 reduces the Oklahoma corporate income tax rate from 6% to 4%. During 2021, AEP recorded an immaterial amount of Income Tax Benefit as a result of remeasuring Oklahoma deferred taxes at the lowered statutory tax rate of 4%. The enacted legislation does not impact APCo, I&M or OPCo.

In November 2021, Louisiana approved Constitutional Amendment 2, thereby also enacting HB 292. HB 292 reduces the Louisiana corporate income tax rate from 8% to 7.5%. In the fourth quarter of 2021, AEP recorded an immaterial amount of Income Tax Expense as a result of remeasuring Louisiana deferred taxes at the lowered statutory tax rate of 7.5%. The enacted legislation does not impact AEP Texas, APCo, I&M, OPCo or PSO.

In December 2021, Arkansas enacted HB 1001. HB 1001 reduces the Arkansas corporate income tax rate from 5.9% to 5.7%, with additional reductions to 5.3% contingent upon future events. In the fourth quarter of 2021, AEP recorded an immaterial amount of Income Tax Expense as a result of remeasuring Arkansas deferred taxes at the lowered statutory tax rate of 5.7%. The enacted legislation does not impact AEP Texas, APCo, I&M, OPCo or PSO.

In August 2022, Arkansas enacted Senate Bill 1. Senate Bill 1 reduces the Arkansas corporate income tax rate from 5.7% to 5.3%. In the third quarter of 2022, AEP recorded an immaterial amount of Income Tax Expense as a result of remeasuring Arkansas deferred taxes at the lowered statutory tax rate of 5.3%. The enacted legislation does not impact AEP Texas, APCo, I&M, OPCo or PSO.

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, 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

Year Ended December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 279.6	$ 17.4	$ 2.6	$ 19.1	$ 101.5	$ 17.1	$ 7.8	$ 9.4
Finance Lease Cost:								
Amortization of Right-of-Use Assets	61.9	6.3	—	7.4	6.5	4.7	3.5	10.9
Interest on Lease Liabilities	15.4	1.5	—	2.7	3.1	0.9	0.7	2.2
Total Lease Rental Costs (a)	$ 356.9	$ 25.2	$ 2.6	$ 29.2	$ 111.1	$ 22.7	$ 12.0	$ 22.5

(a) Excludes variable and short-term lease costs, which were immaterial.

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

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 %

December 31, 2021	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	10.39	5.91	2.95	5.68	5.87	6.69	20.89	20.24
Finance Leases	2.95	5.51	0.00	4.97	2.10	5.54	6.18	4.53
Weighted-Average Discount Rate:								
Operating Leases	3.35 %	3.53 %	0.90 %	3.42 %	3.46 %	3.56 %	3.35 %	3.34 %
Finance Leases	3.26 %	4.31 %	— %	7.16 %	3.02 %	4.19 %	4.23 %	4.68 %

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

Year Ended December 31, 2021	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	$ 279.9	$ 18.0	$ 1.6	$ 19.3	$ 92.9	$ 19.0	$ 8.7	$ 11.6
Operating Cash Flows Used for Finance Leases	14.3	1.4	—	2.4	2.9	0.8	0.6	2.5
Financing Cash Flows Used for Finance Leases	64.0	6.7	—	7.7	6.8	4.9	3.2	10.9
Non-cash Acquisitions Under Operating Leases	$ 117.0	$ 4.4	$ 2.1	$ 4.2	$ 2.6	$ 4.2	$ 33.4	$ 42.9

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, 2022	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
Property, Plant and Equipment Under Finance Leases:									
Generation	$ 120.5		$ —	$ —	$ 41.1	$ 28.0	$ —	$ 0.6	$ 25.9
Other Property, Plant and Equipment	321.2		53.7	—	20.1	40.6	32.7	25.2	58.3
Total Property, Plant and Equipment	441.7		53.7	—	61.2	68.6	32.7	25.8	84.2
Accumulated Amortization	229.3		23.6	—	31.9	34.8	13.8	10.8	54.6
Net Property, Plant and Equipment Under Finance Leases	$ 212.4	(a)	$ 30.1	$ —	$ 29.3	$ 33.8	$ 18.9	$ 15.0	$ 29.6
Obligations Under Finance Leases:									
Noncurrent Liability	$ 168.2		$ 23.1	$ —	$ 21.6	$ 27.1	$ 14.2	$ 11.7	$ 31.3
Liability Due Within One Year	57.2		7.0	—	7.7	6.9	4.7	3.3	10.9
Total Obligations Under Finance Leases	$ 225.4	(b)	$ 30.1	$ —	$ 29.3	$ 34.0	$ 18.9	$ 15.0	$ 42.2

December 31, 2021	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
Property, Plant and Equipment Under Finance Leases:									
Generation	$ 388.8		$ —	$ —	$ 42.8	$ 156.8	$ —	$ 0.6	$ 34.3
Other Property, Plant and Equipment	323.8		50.7	—	20.4	42.1	32.1	23.9	55.7
Total Property, Plant and Equipment	712.6		50.7	—	63.2	198.9	32.1	24.5	90.0
Accumulated Amortization	222.4		19.9	—	27.5	38.2	12.8	9.2	47.8
Net Property, Plant and Equipment Under Finance Leases	$ 490.2	(a)	$ 30.8	$ —	$ 35.7	$ 160.7	$ 19.3	$ 15.3	$ 42.2
Obligations Under Finance Leases:									
Noncurrent Liability	$ 196.1		$ 24.2	$ —	$ 28.1	$ 31.7	$ 14.9	$ 12.3	$ 38.9
Liability Due Within One Year	304.6		6.6	—	7.6	130.5	4.4	3.0	10.8
Total Obligations Under Finance Leases	$ 500.7	(b)	$ 30.8	$ —	$ 35.7	$ 162.2	$ 19.3	$ 15.3	$ 49.7

(a) Amount excludes $369 thousand and $3 million of Net Property, Plant and Equipment Under Finance Leases classified as Assets Held for Sale on the balance sheet for the years ended December 31, 2022 and 2021, respectively. See “Disposition of KPCo and KTCo” section of Note 7 for additional information.

(b) Amount excludes $369 thousand and $3 million of Obligations Under Finance Leases classified as Liabilities Held for Sale on the balance sheet for the years ended December 31, 2022 and 2021, respectively. See “Disposition of KPCo and KTCo” section of Note 7 for additional information.

December 31, 2022	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
Operating Lease Assets	$ 645.0	(a)	$ 94.7	$ 2.7	$ 73.6	$ 64.3	$ 73.8	$ 106.1	$ 123.4
Obligations Under Operating Leases:									
Noncurrent Liability	$ 552.1		$ 67.8	$ 1.5	$ 59.1	$ 48.9	$ 60.3	$ 99.3	$ 120.2
Liability Due Within One Year	113.4		28.6	1.3	15.0	16.0	13.5	8.9	8.4
Total Obligations Under Operating Leases	$ 665.5	(b)	$ 96.4	$ 2.8	$ 74.1	$ 64.9	$ 73.8	$ 108.2	$ 128.6

December 31, 2021	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
Operating Lease Assets	$ 578.3	(a)	$ 73.6	$ 2.0	$ 66.9	$ 63.5	$ 81.2	$ 68.9	$ 80.1
Obligations Under Operating Leases:									
Noncurrent Liability	$ 492.8		$ 61.3	$ 1.3	$ 52.4	$ 48.9	$ 68.6	$ 62.2	$ 77.7
Liability Due Within One Year	97.6		14.0	0.9	15.1	15.5	13.1	6.9	8.1
Total Obligations Under Operating Leases	$ 590.4	(b)	$ 75.3	$ 2.2	$ 67.5	$ 64.4	$ 81.7	$ 69.1	$ 85.8

(a) Amount excludes $528 thousand and $11 million of Operating Lease Assets classified as Assets Held for Sale on the balance sheet for the years ended December 31, 2022 and 2021, respectively. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

(b) Amount excludes $578 thousand and $11 million of Obligations Under Operating Leases classified as Liabilities Held for Sale on the balance sheet for the years ended December 31, 2022 and 2021, respectively. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

Future minimum lease payments consisted of the following as of December 31, 2022:

Finance Leases	AEP (a)	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2023	$ 67.8	$ 8.3	$ —	$ 9.6	$ 9.2	$ 5.4	$ 3.8	$ 12.4
2024	71.4	7.2	—	8.8	12.1	4.6	3.3	16.5
2025	40.9	5.5	—	7.5	6.3	3.2	2.5	6.1
2026	24.9	4.4	—	2.9	3.9	2.6	2.2	2.8
2027	19.2	3.5	—	1.8	3.4	2.1	1.8	2.4
After 2027	32.6	5.5	—	2.8	7.6	3.4	3.7	5.6
Total Future Minimum Lease Payments	256.8	34.4	—	33.4	42.5	21.3	17.3	45.8
Less: Imputed Interest	31.4	4.3	—	4.1	8.5	2.4	2.3	3.6
Estimated Present Value of Future Minimum Lease Payments	$ 225.4	$ 30.1	$ —	$ 29.3	$ 34.0	$ 18.9	$ 15.0	$ 42.2

(a) Amount excludes $369 thousand of Obligations Under Finance Leases classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

Operating Leases	AEP (a)	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2023	$ 138.5	$ 32.3	$ 1.4	$ 17.5	$ 18.8	$ 16.4	$ 11.5	$ 14.4
2024	125.7	29.7	0.9	14.6	17.7	14.9	10.7	12.7
2025	86.6	13.1	0.4	11.8	9.2	13.2	9.5	11.4
2026	75.5	10.9	0.2	10.3	8.3	12.0	8.6	10.2
2027	65.6	8.3	—	9.1	7.5	10.7	7.8	8.8
After 2027	352.0	11.7	—	19.2	9.8	15.7	116.4	141.8
Total Future Minimum Lease Payments	843.9	106.0	2.9	82.5	71.3	82.9	164.5	199.3
Less: Imputed Interest	178.4	9.6	0.1	8.4	6.4	9.1	56.3	70.7
Estimated Present Value of Future Minimum Lease Payments	$ 665.5	$ 96.4	$ 2.8	$ 74.1	$ 64.9	$ 73.8	$ 108.2	$ 128.6

(a) Amount excludes $578 thousand of Obligations Under Operating Leases classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

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, 2022, 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	$ 46.0
AEP Texas	11.1
APCo	6.1
I&M	4.4
OPCo	7.6
PSO	4.8
SWEPCo	5.3

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. Certain boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the respective lessors, ensuring future payments under such leases with maturities up to 2027. As of December 31, 2022, the maximum potential amount of future payments required under the guaranteed leases was $27 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor's rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of December 31, 2022, AEP's boat and barge lease guarantee liability was $2 million, of which $1 million was recorded in Other Current Liabilities and $1 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

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

Lessor Activity

The Registrants' lessor activity was immaterial as of and for the twelve months ended December 31, 2022 and December 31, 2021, 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, 2019	514,373,631	20,204,160	
Issued	2,434,723	—	
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	

(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 2020, AEP filed a prospectus supplement and executed an Equity Distribution Agreement, pursuant to which AEP may sell, from time to time, up to an aggregate of $1 billion of its common stock through an ATM offering program, including an equity forward sales component. The compensation paid to the selling agents by AEP may be up to 2% of the gross offering proceeds of the shares. There were no issuances under the ATM program for the year ended December 31, 2022.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2022	Interest Rate Ranges as of December 31, 2022	Interest Rate Ranges as of December 31, 2021	Outstanding as of December 31, 2022	Outstanding as of December 31, 2021
AEP					(in millions)	
Senior Unsecured Notes	2022-2052	3.96%	0.75%-7.00%	0.61%-7.00%	$ 29,486.2	$ 27,497.3
Pollution Control Bonds (a)	2022-2036 (b)	2.76%	0.63%-4.55%	0.19%-4.55%	1,705.3	1,804.5
Notes Payable – Nonaffiliated (c)	2022-2032	4.29%	0.93%-6.37%	0.79%-6.37%	269.7	211.3
Securitization Bonds	2023-2029 (d)	2.91%	2.01%-3.77%	2.01%-3.77%	487.8	603.5
Spent Nuclear Fuel Obligation (e)					285.6	281.3
Junior Subordinated Notes (f)	2024-2027	2.35%	1.30%-3.88%	1.30%-3.88%	2,381.3	2,373.0
Other Long-term Debt	2022-2059	5.52%	1.15%-13.72%	0.91%-13.72%	1,006.7	683.6
Total Long-term Debt Outstanding (g)					$ 35,622.6	$ 33,454.5
AEP Texas						
Senior Unsecured Notes	2023-2052	4.06%	2.10%-6.76%	2.10%-6.76%	$ 4,702.7	$ 4,135.5
Pollution Control Bonds	2023-2030 (b)	3.42%	0.90%-4.55%	0.90%-4.55%	440.2	439.9
Securitization Bonds	2024-2029 (d)	2.50%	2.06%-2.84%	2.06%-2.84%	314.4	404.7
Other Long-term Debt	2025-2059	5.67%	4.50%-5.67%	1.35%-4.50%	200.5	200.7
Total Long-term Debt Outstanding					$ 5,657.8	$ 5,180.8
AEPTCo						
Senior Unsecured Notes	2023-2052	3.83%	2.75%-5.52%	2.75%-5.52%	$ 4,782.8	$ 4,343.9
Total Long-term Debt Outstanding					$ 4,782.8	$ 4,343.9
APCo						
Senior Unsecured Notes	2025-2050	4.68%	2.70%-7.00%	2.70%-7.00%	$ 4,581.4	$ 4,083.7
Pollution Control Bonds (a)	2024-2036 (b)	2.74%	0.63%-3.80%	0.19%-2.75%	429.4	529.5
Securitization Bonds	2023-2028 (d)	3.67%	2.01%-3.77%	2.01%-3.77%	173.3	198.8
Other Long-term Debt	2023-2026	5.34%	4.84%-13.72%	1.24%-13.72%	226.4	126.9
Total Long-term Debt Outstanding					$ 5,410.5	$ 4,938.9
I&M						
Senior Unsecured Notes	2023-2051	4.19%	3.20%-6.05%	3.20%-6.05%	$ 2,597.3	$ 2,595.5
Pollution Control Bonds (a)	2025 (b)	2.49%	0.75%-3.05%	0.75%-3.05%	189.0	188.7
Notes Payable – Nonaffiliated (c)	2023-2027	4.26%	0.93%-5.93%	0.79%-1.24%	183.8	122.2
Spent Nuclear Fuel Obligation (e)					285.6	281.3
Other Long-term Debt	2025	6.00%	6.00%	6.00%	5.1	7.3
Total Long-term Debt Outstanding					$ 3,260.8	$ 3,195.0
OPCo						
Senior Unsecured Notes	2030-2051	3.87%	1.63%-6.60%	1.63%-6.60%	$ 2,969.7	$ 2,967.8
Other Long-term Debt	2028	1.15%	1.15%	1.15%	0.6	0.7
Total Long-term Debt Outstanding					$ 2,970.3	$ 2,968.5
PSO						
Senior Unsecured Notes	2025-2051	3.74%	2.20%-6.63%	2.20%-6.63%	$ 1,785.6	$ 1,785.5
Other Long-term Debt	2025-2027	5.69%	3.00%-5.75%	1.47%-3.00%	127.2	128.0
Total Long-term Debt Outstanding					$ 1,912.8	$ 1,913.5
SWEPCo						
Senior Unsecured Notes	2026-2051	3.57%	1.65%-6.20%	1.65%-6.20%	$ 3,297.6	$ 3,295.1
Notes Payable – Nonaffiliated (c)	2024-2032	5.38%	4.58%-6.37%	4.58%-6.37%	55.9	59.1
Other Long-term Debt	2028	4.68%	4.68%	4.68%	38.1	41.0
Total Long-term Debt Outstanding					$ 3,391.6	$ 3,395.2

(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.

(g) Amount excludes $1.2 billion and $1.1 billion of Total Long-term Debt Outstanding classified as Liabilities Held for Sale on the balance sheet as of December 31, 2022 and 2021, respectively. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

As of December 31, 2022, outstanding long-term debt was payable as follows:

	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
2023	$ 1,996.4		$ 278.5	$ 60.0	$ 251.8	$ 341.8	$ 0.1	$ 0.5	$ 6.2
2024	1,525.2	(a)	96.0	95.0	113.5	56.4	0.1	0.6	6.2
2025	3,253.9	(b)	524.5	90.0	673.3	220.5	0.1	250.6	6.2
2026	1,554.0		75.0	425.0	30.9	8.5	0.1	50.6	906.2
2027	2,211.9		25.6	—	355.6	1.7	0.1	0.3	6.2
After 2027	25,388.8		4,706.4	4,166.0	4,031.8	2,660.6	3,000.1	1,625.0	2,488.2
Principal Amount	35,930.2		5,706.0	4,836.0	5,456.9	3,289.5	3,000.6	1,927.6	3,419.2
Unamortized Discount, Net and Debt Issuance Costs	(307.6)		(48.2)	(53.2)	(46.4)	(28.7)	(30.3)	(14.8)	(27.6)
Total Long-term Debt Outstanding	$ 35,622.6	(c)	$ 5,657.8	$ 4,782.8	$ 5,410.5	$ 3,260.8	$ 2,970.3	$ 1,912.8	$ 3,391.6

(a) Amount includes $805 million of Junior Subordinated Notes. See "Equity Units" section below for additional information.
(b) Amount includes $850 million of Junior Subordinated Notes. See "Equity Units" section below for additional information.
(c) Amount excludes $1.2 billion of Total Long-term Debt Outstanding classified as Liabilities Held for Sale on the balance sheet as of December 31, 2022. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

Long-term Debt Subsequent Events

In January and February 2023, I&M retired $8 million and $8 million, respectively, of Notes Payable related to DCC Fuel.

In January 2023, PSO issued $475 million of 5.25% Senior Unsecured Notes due in 2033.

In February 2023, AEP Texas retired $12 million of Securitization Bonds.

In February 2023, 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 (notes) due in 2025 and a forward equity purchase contract which settles after three years in August 2023. The notes are expected to be remarketed in 2023, at which time the interest rate will reset at the then-current market rate. Investors may choose to remarket their notes to receive the remarketing proceeds and use those funds to settle the forward equity purchase contract, or accept the remarketed debt and use other funds for the equity purchase. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the principal. The Equity Units carry an annual distribution rate of 6.125%, which is comprised of a quarterly coupon rate of interest of 1.30% and a quarterly forward equity purchase contract payment of 4.825%.

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

- If the AEP common stock market price is equal to or greater than $99.95: 0.5003 shares per contract.
- If the AEP common stock market price is less than $99.95 but greater than $83.29: a number of shares per contract equal to $50 divided by the applicable market price. The holder receives a variable number of shares at $50.
- If the AEP common stock market price is less than or equal to $83.29: 0.6003 shares per contract.

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

At the time of issuance, the $850 million of notes were recorded within Long-term Debt on the balance sheets. The present value of the purchase contract payments of $121 million were recorded in Deferred Credits and Other Noncurrent Liabilities with a current portion in Other Current Liabilities at the time of issuance, representing the obligation to make forward equity contract payments, with an offsetting reduction to Paid-in Capital. The difference between the face value and present value of the purchase contract payments will be accreted to Interest Expense on the statements of income over the three year period ending in 2023. The liability recorded for the contract payments is considered non-cash and excluded from the statements of cash flows. Until settlement of the forward equity purchase contract, earnings per-share dilution resulting from the equity unit issuance will be determined under the treasury stock method. The maximum amount of shares AEP will be required to issue to settle the purchase contract is 10,205,100 shares (subject to an anti-dilution adjustment).

2019 Equity Units

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

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes (notes) due in 2024 and a forward equity purchase contract which settled after three years in 2022. In January 2022, AEP successfully remarketed the notes on behalf of holders of the corporate units and did not directly receive any proceeds therefrom. Instead, the holders of the corporate units used the debt remarketing proceeds to settle the forward equity purchase contract with AEP. The interest rate on the notes was reset to 2.031% with the maturity remaining in 2024. In March 2022, AEP issued 8,970,920 shares of AEP common stock and received proceeds totaling $805 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.

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 1.9% of consolidated tangible net assets as of December 31, 2022. 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, 2022, 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 $16.2 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2022, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 3,023.0 (a)	$ 1,105.7	$ —	$ 543.1	$ 688.2	$ —	$ —	$ 373.0

(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, 2022, AEP had $8.1 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.6 billion, $1.5 billion and $1.4 billion of dividends to common shareholders for the years ended December 31, 2022, 2021 and 2020, 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, 2022, AEP had $5 billion in revolving credit facilities to support its commercial paper program. Securitized Debt for Receivables, for the year ended 2022, had a weighted-average interest rate of 1.84% and a maximum amount outstanding of $750 million. The commercial paper program, for the year ended 2022, had a weighted-average interest rate of 2.74% and a maximum amount outstanding of $2.9 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2022		2021	
Company	Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
AEP	Securitized Debt for Receivables (b)	$ 750.0	4.67 %	$ 750.0	0.19 %
AEP	Commercial Paper	2,862.2	4.80 %	1,364.0	0.34 %
AEP	Term Loan	—	— %	500.0	0.81 %
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 %	—	— %
	Total Short-term Debt	$ 4,112.2		$ 2,614.0	

(a) Weighted-average rate as of December 31, 2022 and 2021, respectively.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program – AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2022 and 2021 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, 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	(199.9) (a)	820.0 (b)
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

Year Ended December 31, 2021:

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, 2021		Authorized Short-term Borrowing Limit	
			(in millions)					
AEP Texas	$ 355.5	$ 104.7	$ 172.5	$ 40.0	$ (26.9)		$ 500.0	
AEPTCo	444.9	117.3	189.1	29.7	(108.0)	(a)	820.0	(b)
APCo	199.3	616.9	87.5	118.3	(178.5)		500.0	
I&M	166.5	368.2	110.4	67.7	(71.8)		500.0	
OPCo	259.2	622.9	61.6	127.2	42.0		500.0	
PSO	267.7	747.3	134.0	113.1	(72.3)		400.0	
SWEPCo	280.3	561.9	142.4	287.4	153.8		400.0	

(a) Amount excludes $4 million of Advances to Affiliates classified as Assets Held for Sale and $1 million of Advances from Affiliates classified as Liabilities Held for Sale on the AEP Transco balance sheet for the years ended December 31, 2022 and 2021, respectively. See "Dispositions of KPCo and KTCo" section of Note 7 for additional information.

(b) 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, 2022 and 2021 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, 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

Year Ended December 31, 2021:

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, 2021
		(in millions)	
AEP Texas	$ 7.1	$ 6.9	$ 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, 2022 and 2021 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, 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)

Year Ended December 31, 2021:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2021	Loans to AEP as of December 31, 2021	Authorized Short-term Borrowing Limit	
(in millions)							
$ 14.6	$ 224.2	$ 1.8	$ 118.0	$ 1.5	$ 12.7	$ 50.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Years Ended December 31,		
	2022	2021	2020
Maximum Interest Rate	5.28 %	0.48 %	2.70 %
Minimum Interest Rate	0.10 %	0.02 %	0.27 %

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	2022	2021	2020	2022	2021	2020
AEP Texas	1.08 %	0.33 %	1.51 %	1.99 %	0.26 %	0.81 %
AEPTCo	1.81 %	0.32 %	1.29 %	2.47 %	0.10 %	1.99 %
APCo	2.34 %	0.41 %	2.12 %	2.39 %	0.25 %	0.85 %
I&M	2.57 %	0.33 %	1.07 %	2.20 %	0.23 %	1.18 %
OPCo	3.51 %	0.27 %	0.99 %	1.22 %	0.14 %	2.06 %
PSO	2.65 %	0.34 %	0.92 %	0.75 %	0.07 %	1.95 %
SWEPCo	2.80 %	0.26 %	1.27 %	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
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 %
2020	AEP Texas	2.70 %	0.27 %	1.18 %
2020	SWEPCo	2.70 %	0.27 %	1.18 %

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
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 %
2020	2.70 %	0.27 %	2.70 %	0.27 %	1.20 %	1.13 %

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	2022	2021	2020
		(in millions)	
AEP Texas	$ 0.9	$ 0.3	$ 0.8
AEPTCo	3.5	0.6	1.5
APCo	5.6	0.1	2.8
I&M	2.9	0.2	1.4
OPCo	2.3	0.1	1.8
PSO	5.5	0.3	0.6
SWEPCo	4.9	0.3	1.5

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 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	2022	2021	2020
		(in millions)	
AEP Texas	$ 2.6	$ 0.1	$ 0.7
AEPTCo	1.6	0.4	2.4
APCo	2.8	0.3	0.7
I&M	0.5	0.2	0.2
OPCo	0.4	0.1	—
PSO	0.3	—	0.1
SWEPCo	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 $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility. The $125 million facility was renewed in September 2022 and amended to extend the expiration date to September 2024. The $625 million facility also expires in September 2024. As of December 31, 2022, the affiliated utility subsidiaries, with the exception of SWEPCo, were in compliance with all requirements under the agreement. SWEPCo temporarily eased credit policies from August 2022 through October 2022 to assist customers with higher than normal bills driven by increased fuel costs and, in turn, experienced higher than normal aged receivables. In response, in January 2023, AEP Credit amended its receivables securitization agreement to increase the eligibility criteria related to their aged receivables requirements to bring SWEPCo back into compliance.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31, 2022	2021	2020
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	1.84 %	0.19 %	0.85 %
Net Uncollectible Accounts Receivable Written Off	$ 29.5	$ 26.5	$ 15.3

	December 31, 2022	2021
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,167.7	$ 995.2
Short-term – Securitized Debt of Receivables	750.0	750.0
Delinquent Securitized Accounts Receivable	44.2	57.9
Bad Debt Reserves Related to Securitization	39.7	42.8
Unbilled Receivables Related to Securitization	360.9	307.1

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 pending 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. 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, 2022	December 31, 2021
	(in millions)	
APCo	$ 194.4	$ 153.1
I&M	166.9	156.9
OPCo	478.6	392.7
PSO	155.5	114.5
SWEPCo	194.0	153.0

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

Company	Years Ended December 31, 2022	2021 (a)	2020
		(in millions)	
APCo	$ 9.4	$ 4.9	$ 5.2
I&M	9.7	7.0	7.9
OPCo	29.8	8.3	24.1
PSO	7.4	3.4	4.8
SWEPCo	9.4	5.4	6.7

(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, 2022	2021	2020
		(in millions)	
APCo	$ 1,552.9	$ 1,324.1	$ 1,272.9
I&M	2,045.6	1,927.0	1,891.8
OPCo	3,101.3	2,458.5	2,366.2
PSO	1,809.5	1,406.4	1,221.0
SWEPCo	1,858.4	1,636.1	1,593.8

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, 2022, 5,249,391 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 as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to a share of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance shares and AEP career shares accrue as additional shares. Management records compensation cost for performance shares over an approximately three-year vesting period. 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 2022, 2021 and 2020 have three performance metrics: (a) three-year cumulative operating earnings per-share with a 50% weight, (b) total shareholder return with a 40% weight and (c) non-emitting generation capacity as a percentage of total owned and purchased capacity with a 10% weight. Performance shares granted in 2019 had two equally-weighted performance metrics: (a) three-year cumulative operating earnings per-share and (b) total shareholder return. The three-year cumulative operating earnings per-share and 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, 2022	2021	2020
Awarded Shares (in thousands)	530.3	565.0	424.8
Weighted-Average Share Fair Value at Grant Date	$ 97.61	$ 81.02	$ 116.56
Vesting Period (in years)	3	3	3

Performance Shares and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2022	2021	2020
Awarded Shares (in thousands)	63.3	74.5	73.4
Weighted-Average Fair Value at Grant Date	$ 98.73	$ 84.48	$ 84.87
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, 2022	2021	2020
Certified Performance Score	131.1 %	102.9 %	128.2 %
Performance Shares Earned	512,660	537,166	757,858
Performance Shares Mandatorily Deferred as AEP Career Shares	28,282	14,613	13,614
Performance Shares Voluntarily Deferred into the Incentive Compensation Deferral Program	23,609	22,915	26,936
Performance Shares to be Settled (a)	460,769	499,638	717,308

(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, 2022	2021 (in millions)	2020
AEP Common Stock Settlements for Performance Shares	$ 43.2	$ 54.7	$ 75.4
AEP Common Stock Settlements for Career Share Distributions	5.1	4.0	1.9

A summary of the status of AEP's nonvested Performance Shares as of December 31, 2022 and changes during the year ended December 31, 2022 were as follows:

Nonvested Performance Shares	Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2022	923.8	$ 96.15
Awarded	530.3	97.61
Dividends	45.5	98.73
Vested (a)	(395.8)	116.06
Forfeited	(91.6)	84.81
Nonvested as of December 31, 2022	1,012.2	90.27

(a) The vested Performance Shares will be converted to 461 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:

	Years Ended December 31,		
Assumptions	**2022**	**2021**	**2020**
Valuation Period (in years) (a)	2.86	2.88	2.87
Expected Volatility Minimum	25.92 %	25.87 %	13.67 %
Expected Volatility Maximum	40.82 %	39.90 %	28.15 %
Expected Volatility Average	31.09 %	31.01 %	16.39 %
Dividend Rate (b)	— %	— %	— %
Risk Free Rate	1.64 %	0.19 %	1.40 %

(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, except the RSUs granted prior to 2017 to AEP's executive officers which settled in cash. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. For RSUs that settle in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs that settled in cash, compensation cost was recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting was determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

The HR Committee awarded RSUs, including additional units awarded as dividends, as follows:

Restricted Stock Units	Years Ended December 31, 2022	2021	2020
Awarded Units (in thousands)	290.4	280.0	268.7
Weighted-Average Grant Date Fair Value	$ 90.48	$ 80.39	$ 94.38

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

Restricted Stock Units	Years Ended December 31, 2022	2021	2020
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 17.8	$ 20.5	$ 22.9
Intrinsic Value of Restricted Stock Units Vested (a)	20.3	22.0	25.2

(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, 2022 and changes during the year ended December 31, 2022 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2022	424.3	$ 84.86
Awarded	290.4	90.48
Vested	(209.0)	85.15
Forfeited	(46.1)	85.80
Nonvested as of December 31, 2022	459.6	88.05

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2022 was $44 million and the weighted-average remaining contractual life was 1.8 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.

Cash settlements for stock unit distributions were immaterial for the years ended December 31, 2022, 2021 and 2020. No stock units were settled in AEP common stock for the years ended December 31, 2022, 2021 and 2020.

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	**2022**	**2021**	**2020**
Awarded Units (in thousands)	14.5	12.6	12.1
Weighted-Average Grant Date Fair Value	$ 95.16	$ 84.54	$ 83.80

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	**2022**	**2021**	**2020**
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 63.3	$ 61.1	$ 53.8
Actual Tax Benefit	8.0	8.7	7.2
Total Compensation Cost Capitalized	16.0	16.9	20.4

(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, 2022, there was $78 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 1.41 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 "AEP System Tax Allocation" section of Note 1 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective Off-system Sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

System Integration Agreement (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

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

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M (a)	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
Other Revenues	3.5	7.4	8.9	7.6	22.4	2.9	1.1
Total Affiliated Revenues	$ 3.5	$ 1,283.8	$ 256.1	$ 15.3	$ 18.8	$ 2.9	$ 53.9

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M (a)	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
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	$ 3.8	$ 24.8	$ 4.2	$ 41.0

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M (a)	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2020							
Direct Sales to East Affiliates	$ —	$ —	$ 112.5	$ —	$ —	$ —	$ —
Auction Sales to OPCo (b)	—	—	5.3	3.1	—	—	—
Direct Sales to AEPEP	87.5	—	—	—	—	—	—
Transmission Revenues	—	885.0	49.1	2.9	16.6	—	37.4
Other Revenues	3.3	11.3	7.8	4.5	24.9	5.2	1.6
Total Affiliated Revenues	$ 90.8	$ 896.3	$ 174.7	$ 10.5	$ 41.5	$ 5.2	$ 39.0

(a) I&M's affiliated revenues exclude capacity sales to KPCo from Rockport Plant, Unit 2 and barging, urea transloading and other transportation services to affiliates. See sections "Unit Power Agreements" and "I&M Barging, Urea Transloading and Other Services" below for additional information.

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

The tables below represent the purchased power expenses incurred for purchases from affiliates. AEP Texas, AEPTCo, APCo, PSO and SWEPCo did not purchase any or an immaterial amount of power from affiliates for the years ended December 31, 2022, 2021 and 2020.

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2022		
Auction Purchases from AEPEP (a)	$ —	$ 9.8
Direct Purchases from AEGCo	241.8	—
Total Affiliated Purchases	$ 241.8	$ 9.8

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2021		
Auction Purchases from AEPEP (a)	$ —	$ 26.6
Auction Purchases from AEP Energy (a)	—	25.3
Direct Purchases from AEGCo	217.9	—
Total Affiliated Purchases	$ 217.9	$ 51.9

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2020		
Auction Purchases from AEPEP (a)	$ —	$ 51.0
Auction Purchases from AEP Energy (a)	—	58.7
Auction Purchases from AEPSC (a)	—	10.0
Direct Purchases from AEGCo	172.8	—
Total Affiliated Purchases	$ 172.8	$ 119.7

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

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

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.

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

	Years Ended December 31,		
Company	**2022**	**2021**	**2020**
		(in millions)	
APCo	$ 345.1	$ 302.0	$ 243.2
I&M	220.8	186.7	145.9
OPCo	608.2	508.9	417.4

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

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and SWEPCo. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.

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

	Years Ended December 31,		
Company	**2022**	**2021**	**2020**
		(in millions)	
PSO	$ 110.8	$ 94.7	$ 69.7
SWEPCo	62.1	56.2	31.3

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

AEPTCo provides transmission services to affiliates in accordance with the OATT, TA and TCA. AEPTCo recorded affiliated transmission revenues in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

ERCOT Transmission Service Charges (Applies to AEP and AEP Texas)

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $28 million, $28 million and $28 million for transmission services for the years ended December 31, 2022, 2021 and 2020, respectively. The billings are recorded in Other Operation expenses on AEP Texas' statements of income.

Oklaunion PPA between AEP Texas and AEPEP (Applies to AEP Texas)

In 2007, AEP Texas entered into a PPA with an affiliate, AEPEP, whereby AEP Texas agreed to sell AEPEP 100% of AEP Texas' capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Power Station. The PPA was approved by the FERC. In September 2018, the co-owners of Oklaunion Power Station voted to close the plant in 2020. Effective October 2018, AEP Texas increased depreciation expense to ensure the plant balances are fully depreciated as of September 2020 and recovered through the PPA billings to AEPEP. Under the early termination provisions of the PPA, AEPEP paid AEP Texas the full Property, Plant and Equipment balance through depreciation payments until termination of the PPA due to the plant closing in September 2020. See "Dispositions" section of Note 7 for additional information.

AEP Texas recorded revenue of $88 million from AEPEP for the year ended December 31, 2020. This amount is included in Sales to AEP Affiliates on AEP Texas' statements of income.

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

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the following costs in Other Operation expense related to these agreements:

	Years Ended December 31,		
Billing Company	**2022**	**2021**	**2020**
		(in millions)	
APCo	$ 2.5	$ 2.4	$ 0.9
I&M	6.1	4.8	3.0
KPCo	0.6	0.5	0.4
OPCo	5.2	4.6	4.5
PSO	0.1	0.4	0.4
WPCo	0.2	0.2	0.2

APCo, I&M, KPCo, OPCo, PSO and WPCo recorded income related to these agreements in Sales to AEP Affiliates on the statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. 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 I&M Power Agreement 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).

In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in Rockport Plant, Unit 2 effective at the end of the lease term on December 7, 2022. Beginning December 8, 2022, AEGCo and I&M applied the joint plant accounting model to their respective 50% undivided interests in the jointly owned Rockport Plant, Unit 2 as well as any future investments made prior to the current estimated retirement date of December 2028.

Prior to the termination of the Rockport Plant, Unit 2 lease, I&M assigned 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below for additional information. Beginning December 8, 2022, AEGCo billed 100% of its share of the Rockport Plant to I&M and ceased billing to KPCo. KPCo reached an agreement with I&M, from the end of the lease through May 2024, to buy capacity from Rockport Plant, Unit 2 through the PCA at a rate equal to PJM's RPM clearing price. I&M's capacity sales to KPCo were $199 thousand for the year ended December 31, 2022.

UPA between AEGCo and KPCo

On December 7, 2022, the UPA between AEGCo and KPCo ended upon the termination of the Rockport Plant, Unit 2 lease. Previously, pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sold KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo paid AEGCo in consideration for the right to receive such power, the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. As a result of the end of the UPA between AEGCo and KPCo, a prorated bill was recorded from AEGCo to KPCo to reflect costs incurred for the first seven days of December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading costs were $9 million, $11 million and $12 million for the years ended December 31, 2022, 2021 and 2020, respectively. I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance costs were as follows:

	Years Ended December 31,		
Company	**2022**	**2021**	**2020**
		(in millions)	
I&M	$ 0.6	$ 0.3	$ 0.9
PSO	0.6	0.4	0.7
SWEPCo	2.7	2.8	3.0

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

	Years Ended December 31,		
Company	**2022**	**2021**	**2020**
		(in millions)	
AEGCo	$ 11.3	$ 7.6	$ 10.6
APCo	36.1	40.1	43.7
KPCo	2.0	3.1	3.2
WPCo	4.7	3.2	3.3

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value:

Sales

Company	Years Ended December 31, 2022	2021	2020
		(in millions)	
AEP Texas	$ 3.0	$ 0.4	$ 0.9
AEPTCo	2.3	1.4	0.2
APCo	16.0	6.2	5.7
I&M	5.3	7.0	1.5
OPCo	7.6	9.2	7.0
PSO	2.5	0.5	1.1
SWEPCo	1.0	0.4	0.8

Purchases

Company	Years Ended December 31, 2022	2021	2020
		(in millions)	
AEP Texas	$ 1.3	$ 0.4	$ 1.5
AEPTCo	11.6	16.7	6.0
APCo	2.4	1.0	1.3
I&M	2.0	0.6	3.4
OPCo	2.0	1.4	1.2
PSO	7.6	0.3	0.4
SWEPCo	2.8	0.3	2.8

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

AEP Wind Holdings LLC PPAs (Applies to I&M, OPCo and SWEPCo)

Prior to its acquisition, two of the 50% owned joint venture wind farms in the AEP Wind Holdings, LLC portfolio had existing PPAs with I&M, OPCo and SWEPCo. Fowler Ridge 2 has PPAs with I&M and OPCo for a portion of its energy production. The I&M portion totaled $12 million, $10 million and $11 million and the OPCo portion totaled $24 million, $20 million and $23 million respectively, for the years ended December 31, 2022, 2021 and 2020, respectively. The other joint venture wind farm, Flat Ridge 2, has a PPA with SWEPCo for a portion of its energy production which totaled $14 million, $14 million and $14 million of purchased electricity for the years ended December 31, 2022, 2021 and 2020, respectively. AEP disposed of its 50% interest in Flat Ridge 2 in the fourth quarter of 2022. See "Flat Ridge 2 Wind LLC" section of Note 7 for additional information.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Charitable Contributions to AEP Foundation

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

Company	Year Ended December 31, 2022	
	(in millions)	
AEP	$	75.0
AEP Texas		9.9
AEPTCo		11.1
APCo		12.5
I&M		11.0
OPCo		8.1
PSO		5.8
SWEPCo		8.8

In 2021 and 2020, there were no charitable contributions made to the AEP Foundation.

OKTCo Radial Assets Transfer (Applies to AEP, AEPTCo and PSO)

In August 2020, AEPSC filed a request with FERC, on behalf of PSO and OKTCo, to transfer OKTCo's interests in its radial assets to PSO. OKTCo had previously constructed radial assets in the PSO service territory and after the radial assets were placed into service, management determined the radial assets were not eligible to be included as part of OKTCo's SPP OATT formula rates. In October 2020, FERC approved the request and in December 2020, OKTCo completed the transfer of its interest in the radial assets to PSO, through Parent, at net book value. At the transfer date, the net book value of the radial assets were $60 million, before associated tax liabilities.

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, 2022, 2021 and 2020 were $168 million, $162 million and $131 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $155 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon completion of reclamation. The mine end-of-life has been adjusted to March 2023, in order to align with the announced closure of the Pirkey Power Plant. Reclamation is expected to be complete by 2037 at an estimated cost of $135 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, 2022, SWEPCo has recorded $122 million of mine reclamation costs in Asset Retirement Obligations and has collected $89 million through a rider for reclamation costs. The remaining $33 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, 2022, 2021 and 2020 were $84 million, $91 million and $94 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, 2022 and 2021, $70 million and $68 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $71 million and $141 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Transition Funding has securitized transition assets of $125 million and $184 million as of December 31, 2022 and 2021, 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, 2022 and 2021, $24 million and $23 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $150 million and $173 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Restoration Funding has securitized assets of $161 million and $183 million as of December 31, 2022 and 2021, 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 table 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, 2022 and 2021, $26 million and $26 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $147 million and $173 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $160 million and $185 million as of December 31, 2022 and 2021, 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 25% 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 six lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third-parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2022, 2021 and 2020 was $31 million, $30 million and $31 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.

Apple Blossom Wind Holdings LLC and Black Oak Getty Wind Holdings LLC (Applies to AEP)

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

The nonaffiliated interests in the Project Entities are presented in Noncontrolling Interests on the balance sheets. As of December 31, 2022 and 2021, AEP recognized \$94 million and \$108 million, respectively, of Noncontrolling Interests related to the Project Entities in Equity on the balance sheets.

The Project Entities' tax equity partnerships represent substantive profit-sharing arrangements. The method for attributing income and loss to the noncontrolling interests is a balance sheet approach referred to as the hypothetical liquidation at book value (HLBV) method. Under the HLBV method, the income and loss attributable to the noncontrolling interests reflect changes in the amounts the members would hypothetically receive at each balance sheet date under the liquidation provisions of the respective limited liability company agreements, assuming the net assets of these entities were liquidated at recorded amounts, after taking into account any capital transactions, such as contributions or distributions, between the entities and the members. For the years ended December 31, 2022 and 2021, the HLBV method resulted in a loss of \$9 million and \$7 million, respectively, allocated to Noncontrolling Interests.

Santa Rita East (Applies to AEP)

AEP owns an 85% interest in Santa Rita East Wind Energy Holdings, LLC and its wholly-owned subsidiary, Santa Rita East Wind Energy, LLC (collectively, Santa Rita East). Santa Rita East is a partnership whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas. Santa Rita East delivers energy and provides renewable energy credits through three long-term PPAs totaling 260 MWs. The remaining 42 MWs of energy are sold at wholesale into ERCOT. Management has concluded that Santa Rita East is a VIE and that AEP is the primary beneficiary based on its power as managing member of the partnership to direct the activities that most significantly impact Santa Rita East's economic performance. See the tables below for the classification of Santa Rita East's assets and liabilities on the balance sheets.

AEP recognized $24 million, $25 million and $23 million of PTCs attributable to Santa Rita East for the years ended December 31, 2022, 2021 and 2020, respectively, which was recorded in Income Tax Expense (Benefit) on the statements of income. The nonaffiliated interest in Santa Rita East is presented in Noncontrolling Interests on the balance sheets. As of December 31, 2022 and 2021, AEP recorded $58 million and $59 million, respectively, of Noncontrolling Interests related to Santa Rita East in Equity on the balance sheets.

Dry Lake (Applies to AEP)

In November 2020, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% ownership interest in the entity that owns Dry Lake Solar Project (collectively, Dry Lake). Dry Lake is a partnership whose sole purpose is to own, operate and maintain a 100 MW solar generation facility in southern Nevada. In March 2021, AEP closed the transaction and the solar project was placed in-service in May 2021. Dry Lake delivers energy and provides renewable energy credits through a long-term PPA. Management has concluded that Dry Lake is a VIE and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact Dry Lake's economic performance. See the table below for the classification of Dry Lake assets and liabilities on the balance sheets.

The ITC attributable to Dry Lake for the years ended December 31, 2022 and 2021 which was recorded in Income Tax Expense (Benefit) on the statements of income was not material. The nonaffiliated interest in Dry Lake is presented in Noncontrolling Interests on the balance sheets. As of December 31, 2022 and 2021, AEP recognized $34 million and $35 million of Noncontrolling Interest on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2022

	Registrant Subsidiaries				
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding
			(in millions)		
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					
	AEP Credit	Protected Cell of EIS	Transource Energy	Apple Blossom and Black Oak	Santa Rita East	Dry Lake
			(in millions)			
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

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2021

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**AEP Texas Restoration Funding**	**APCo Appalachian Consumer Rate Relief Funding**
			(in millions)		
ASSETS					
Current Assets	$ 77.2	$ 65.2	$ 24.9	$ 24.3	$ 16.0
Net Property, Plant and Equipment	51.8	118.6	—	—	—
Other Noncurrent Assets	104.1	57.2	208.3 (a)	192.6 (b)	187.8 (c)
Total Assets	$ 233.1	$ 241.0	$ 233.2	$ 216.9	$ 203.8
LIABILITIES AND EQUITY					
Current Liabilities	$ 18.9	$ 65.1	$ 71.2	$ 36.1	$ 29.0
Noncurrent Liabilities	214.3	175.9	157.8	179.6	172.9
Equity	(0.1)	—	4.2	1.2	1.9
Total Liabilities and Equity	$ 233.1	$ 241.0	$ 233.2	$ 216.9	$ 203.8

(a) Includes an intercompany item eliminated in consolidation of $24 million.
(b) Includes an intercompany item eliminated in consolidation of $8 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, 2021

	Other Consolidated VIEs					
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Apple Blossom and Black Oak**	**Santa Rita East**	**Dry Lake**
			(in millions)			
ASSETS						
Current Assets	$ 996.6	$ 217.3	$ 38.8	$ 9.9	$ 7.6	$ 4.0
Net Property, Plant and Equipment	—	—	475.4	217.3	437.6	146.1
Other Noncurrent Assets	10.4	—	3.0	11.3	—	0.3
Total Assets	$ 1,007.0	$ 217.3	$ 517.2	$ 238.5	$ 445.2	$ 150.4
LIABILITIES AND EQUITY						
Current Liabilities	$ 953.1	$ 37.5	$ 12.5	$ 6.6	$ 5.8	$ 0.9
Noncurrent Liabilities	0.9	82.3	216.9	5.2	7.0	0.6
Equity	53.0	97.5	287.8	226.7	432.4	148.9
Total Liabilities and Equity	$ 1,007.0	$ 217.3	$ 517.2	$ 238.5	$ 445.2	$ 150.4

Non-Consolidated Significant Variable Interests

DHLC (Applies to AEP and SWEPCo)

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee 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, 2022 were not material, and for the years ended December 31, 2021 and 2020 were $47 million and $142 million, respectively. DHLC paid dividends of $25 million, $0 million, and $0 million to SWEPCo for the years ended December 31, 2022, 2021, and 2020, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2022		2021	
	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	23.8	23.8
SWEPCo's Share of Obligations	—	36.8	—	50.3
Total Investment in DHLC	$ 8.0	$ 44.8	$ 31.4	$ 81.7

OVEC (Applies to AEP and OPCo)

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2022, 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, 2022 and 2021, 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 holds a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors of

OVEC and the representation of the sponsoring companies on the Operating Committee under the intercompany power agreement.

AEP's investment in OVEC was:

	December 31,			
	2022		2021	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Ratio of OVEC Debt (a)	—	478.2	—	492.0
Total Investment in OVEC	$ 4.4	$ 482.6	$ 4.4	$ 496.4

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt was $173 million, $86 million and $219 million as of December 31, 2022 and $177 million, $89 million and $226 million as of December 31, 2021, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity for Resale on the statements of income and is shown in the table below:

	Years Ended December 31,		
Company	2022	2021	2020
	(in millions)		
APCo	$ 119.3	$ 104.3	$ 94.4
I&M	59.7	52.2	47.2
OPCo	151.8	133.0	120.8

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	2022	2021	2020
	(in millions)		
AEP Texas	$ 236.8	$ 206.9	$ 199.4
AEPTCo	286.6	267.1	270.3
APCo	347.5	313.3	294.9
I&M	192.4	200.9	210.2
OPCo	272.5	234.9	232.8
PSO	142.3	123.7	113.2
SWEPCo	192.5	168.6	161.8

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

	December 31,			
	2022		2021	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
AEP Texas	$ 27.8	$ 27.8	$ 22.2	$ 22.2
AEPTCo	31.6	31.6	23.3	23.3
APCo	41.5	41.5	44.1	44.1
I&M	27.7	27.7	21.8	21.8
OPCo	31.1	31.1	25.5	25.5
PSO	17.7	17.7	13.7	13.7
SWEPCo	23.8	23.8	20.5	20.5

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 all 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, 2022, 2021 and 2020 were $242 million, $218 million and $173 million, respectively. The carrying amounts of I&M's liabilities associated with AEGCo as of December 31, 2022 and 2021 were $17 million and $18 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Significant Equity Method Investments in Unconsolidated Entities (Applies to AEP)

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

AEP Wind Holdings, LLC

In September 2022, AEP signed a PSA with a nonaffiliate for AEP's interest in Flat Ridge 2, one of the five joint ventures that were held as of December 31, 2021 by AEP. The transaction closed in the fourth quarter of 2022 and had an immaterial impact on the financial statements. As of December 31, 2022, through AEP Wind Holdings, LLC, AEP holds a 50% interest in four joint ventures in multiple states which own distinct generation facilities. BP Wind Energy holds the other 50% interest in each of these joint ventures. All four wind farms have long-term PPAs for 100% of their energy production. One of the jointly-owned wind farms has PPAs with I&M and OPCo for a portion of its energy production. The joint ventures are not considered VIEs and AEP is not required to consolidate them as AEP does not have a controlling financial interest. However, AEP is able to exercise significant influence over the joint ventures and therefore applies the equity method of accounting.

The following financial figures in the respective periods include the results Flat Ridge 2 prior to its disposal. As of December 31, 2022 and 2021, AEP's carrying value of the investment in the joint ventures was $247 million and $399 million, respectively. As of December 31, 2022 and 2021, the difference between AEP's carrying value and the amount of underlying equity in net assets was $62 million and $(3) million, respectively. The investment includes amounts recognized in AOCI related to interest rate cash flow hedges. AEP's equity earnings (loss) associated with the joint venture wind farms was $(194) million, $(12) million and $2 million for the years ended December 31, 2022, 2021, and 2020, respectively. AEP recognized $39 million, $33 million, and $36 million of PTCs attributable to the joint ventures for the years ended December 31, 2022, 2021, and 2020 respectively, which was recorded in Income Tax Expense (Benefit) on the statements of income. See the "Impairments" section of Note 7 for additional information.

ETT

ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. Berkshire Hathaway Energy, a nonaffiliated entity, holds a 50% membership interest in ETT 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, 2022 and 2021, AEP's investment in ETT was $762 million and $733 million, respectively. AEP's equity earnings associated with ETT were $74 million, $66 million and $68 million for the years ended December 31, 2022, 2021 and 2020 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, 2022 and 2021:

December 31, 2022	AEP		AEP Texas	AEPTCo		APCo	I&M	OPCo	PSO	SWEPCo	
						(in millions)					
Regulated Property, Plant and Equipment											
Generation	$22,523.1	(a)	$ —	$ —		$ 6,776.8	$ 5,534.6	$ —	$ 2,394.8	$ 5,476.2	(a)
Transmission	32,267.8		6,301.5	12,183.2		4,482.8	1,842.2	3,198.6	1,164.4	2,479.8	
Distribution	26,077.2		5,312.8	—		4,933.0	3,024.7	6,450.3	3,216.4	2,659.6	
Other	5,700.4		1,020.4	451.7		849.2	796.1	1,040.6	466.0	582.6	
CWIP	4,630.8	(a)	805.2	1,547.1		705.3	253.0	474.3	219.3	369.5	(a)
Less: Accumulated Depreciation	21,947.1		1,759.5	1,012.2		5,397.3	4,117.8	2,564.3	1,839.4	3,314.8	
Total Regulated Property, Plant and Equipment - Net	69,252.2		11,680.4	13,169.8		12,349.8	7,332.8	8,599.5	5,621.5	8,252.9	
Nonregulated Property, Plant and Equipment - Net	2,030.7		1.2	0.3		29.4	78.7	9.8	5.0	9.3	
Total Property, Plant and Equipment - Net	$71,282.9	(b)	$11,681.6	$13,170.1	(c)	$12,379.2	$ 7,411.5	$ 8,609.3	$ 5,626.5	$ 8,262.2	

December 31, 2021	AEP		AEP Texas	AEPTCo		APCo	I&M	OPCo	PSO	SWEPCo	
						(in millions)					
Regulated Property, Plant and Equipment											
Generation	$21,196.8	(a)	$ —	$ —		$ 6,683.9	$ 5,531.8	$ —	$ 1,802.4	$ 4,734.5	(a)
Transmission	29,866.0		5,849.9	10,886.3		4,322.4	1,783.1	2,992.8	1,107.7	2,316.9	
Distribution	24,440.0		4,917.2	—		4,683.3	2,800.1	6,070.6	3,004.9	2,514.3	
Other	5,249.8		958.7	427.2		668.9	755.1	982.2	433.5	542.0	
CWIP	3,632.4	(a)	551.3	1,394.8		469.9	302.8	365.0	156.0	240.7	(a)
Less: Accumulated Depreciation	20,375.5		1,642.9	772.9		5,047.4	3,885.3	2,457.4	1,707.0	3,002.2	
Total Regulated Property, Plant and Equipment - Net	64,009.5		10,634.2	11,935.4		11,781.0	7,287.6	7,953.2	4,797.5	7,346.2	
Nonregulated Property, Plant and Equipment - Net	1,991.8		1.2	0.3		23.3	23.3	9.8	5.3	53.9	
Total Property, Plant and Equipment - Net	$66,001.3	(b)	$10,635.4	$11,935.7	(c)	$11,804.3	$ 7,310.9	$ 7,963.0	$ 4,802.8	$ 7,400.1	

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

(b) Amount excludes $2.4 billion and $2.3 billion as of December 31, 2022 and 2021, respectively, of Property, Plant and Equipment - Net classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

(c) Amount excludes $170 million and $165 million as of December 31, 2022 and 2021, respectively, of Property, Plant and Equipment - Net classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 7 for additional information.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

Functional Class of Property	2022 Annual Composite Depreciation Rate Ranges	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate Ranges	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate Ranges	2020 Depreciable Life Ranges (in years)
Generation	2.7% - 7.6%	20 - 132	2.7% - 7.8%	20 - 132	2.7% - 6.3%	20 - 132
Transmission	2.0% - 2.7%	24 - 75	2.0% - 2.6%	15 - 75	2.0% - 2.6%	15 - 75
Distribution	2.7% - 3.6%	7 - 78	2.8% - 3.6%	7 - 80	2.7% - 3.7%	7 - 78
Other	3.1% - 14.4%	5 - 75	3.0% - 12.5%	5 - 75	2.8% - 11.3%	5 - 75

AEP Texas

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Transmission	2.2%	50 - 75	2.2%	50 - 75	2.0%	50 - 75
Distribution	2.9%	7 - 70	2.9%	7 - 70	3.1%	7 - 70
Other	6.2%	5 - 50	5.8%	5 - 50	6.1%	5 - 50

AEPTCo

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Transmission	2.6%	24 - 75	2.5%	24 - 75	2.4%	24 - 75
Other	6.6%	5 - 56	6.7%	5 - 56	6.3%	5 - 64

APCo

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Generation	3.6%	35 - 118	3.6%	35 - 118	3.3%	35 - 118
Transmission	2.2%	24 - 75	2.1%	15 - 75	2.2%	15 - 75
Distribution	3.6%	12 - 57	3.5%	12 - 57	3.7%	12 - 57
Other	7.3%	5 - 55	8.5%	5 - 55	7.8%	5 - 55

I&M

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Generation	4.9%	20 - 132	4.7%	20 - 132	4.6%	20 - 132
Transmission	2.5%	44 - 67	2.4%	45 - 70	2.3%	45 - 70
Distribution	3.1%	14 - 71	3.4%	14 - 71	3.4%	14 - 71
Other	10.1%	5 - 45	9.0%	5 - 51	10.2%	5 - 51

OPCo

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	2.7%	11 - 70	2.9%	11 - 70	3.1%	14 - 65
Other	6.1%	5 - 50	6.1%	5 - 50	5.0%	5 - 50

PSO

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Generation	3.1%	30 - 75	2.8%	30 - 75	3.1%	35 - 75
Transmission	2.5%	42 - 75	2.4%	42 - 75	2.2%	45 - 75
Distribution	2.9%	15 - 78	2.9%	15 - 78	2.9%	15 - 78
Other	6.8%	5 - 56	6.1%	5 - 56	5.7%	5 - 64

SWEPCo

Functional Class of Property	2022 Annual Composite Depreciation Rate	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)
Generation	2.7%	30 - 65	2.7%	30 - 65	2.7%	35 - 65
Transmission	2.3%	44 - 70	2.4%	49 - 74	2.3%	47 - 73
Distribution	2.9%	15 - 75	2.8%	15 - 80	2.7%	15 - 67
Other	9.0%	5 - 57	8.6%	5 - 58	8.5%	5 - 52

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo for 2022, 2021 and 2020.

Functional Class of Property	2022 Annual Composite Depreciation Rate Ranges	2022 Depreciable Life Ranges (in years)	2021 Annual Composite Depreciation Rate Ranges	2021 Depreciable Life Ranges (in years)	2020 Annual Composite Depreciation Rate Ranges	2020 Depreciable Life Ranges (in years)
Generation	3.8% - 8.7%	3 - 61	3.8% - 10.4%	10 - 59	3.6% - 4.0%	15 - 59
Transmission	2.8%	10 - 62	2.6%	30 - 40	2.5%	30 - 40
Distribution	NA	NA	NA	NA	NA	NA
Other	25.2%	5 - 35 (a)	16.5%	5 - 35 (a)	16.1%	5 - 50

(a) In 2020 management announced plans to retire the Pirkey Plant in 2023 and the related depreciable lives have been adjusted accordingly. See Note 5 - Effects of Regulation for additional information.
NA Not applicable.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants recorded the following revisions to ARO estimates as of December 31, 2022 and 2021:

- As of December 31, 2022 and 2021, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $2 billion and $1.93 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2022 and 2021, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $3.01 billion and $3.54 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets. In December 2021, I&M recorded a $58 million revision for Cook Plant as a result of the latest decommissioning cost study. The ARO liability was updated and changes from the previous study were driven primarily by general increases in the projected cost of labor and materials.
- In 2020, Virginia's Governor signed House Bill 443 (HB 443) requiring APCo to close certain ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. In June 2021, management completed fully designed and costed project plans for the Glen Lyn Station site and increased ash disposal ARO liabilities by an additional $79 million. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause. APCo is permitted to record carrying costs on the unrecovered balance of closure costs as a weighted-average cost of capital approved by the Virginia SCC. The legislation provides for regulatory recovery of these costs.
- 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.

The following is a reconciliation of the 2022 and 2021 aggregate carrying amounts of ARO by Registrant:

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)(h)	$ 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

Company	ARO as of December 31, 2020	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2021
			(in millions)			
AEP (b)(c)(d)(e)(f)(g)(h)	$ 2,516.7	$ 105.0	$ 22.8	$ (41.4)	$ 138.6	$ 2,741.7
AEP Texas (b)(e)	4.6	0.2	—	(0.4)	—	4.4
APCo (b)(e)	313.1	13.7	—	(6.9)	84.7	404.6
I&M (b)(c)(e)	1,813.8	72.9	0.3	(0.1)	59.4	1,946.3
OPCo (e)	1.9	0.1	—	(0.1)	—	1.9
PSO (b)(e)(g)	47.4	3.3	7.6	(0.7)	—	57.6
SWEPCo (b)(d)(e)(g)	222.1	9.8	9.2	(20.9)	2.5	222.7

(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 billion and $1.93 billion as of December 31, 2022 and 2021, 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.
(h) Includes $18 million and $18 million as of December 31, 2022 and 2021, respectively, of ARO classified as Liabilities Held for Sale on the balance sheet. See “Disposition of KPCo and KTCo” section of Note 7 for additional information.

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, 2022	2021	2020
		(in millions)	
AEP	$ 133.7	$ 139.7	$ 148.1
AEP Texas	19.7	21.5	19.4
AEPTCo	70.7	67.2	74.0
APCo	11.7	15.6	14.6
I&M	9.8	12.8	11.5
OPCo	13.9	10.8	12.5
PSO	1.5	2.4	4.0
SWEPCo	4.9	7.0	7.7

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, 2022	2021	2020
		(in millions)	
AEP	$ 63.0	$ 53.8	$ 66.0
AEP Texas	11.5	10.5	12.5
AEPTCo	22.4	21.0	25.5
APCo	6.5	7.5	7.9
I&M	5.7	5.1	5.7
OPCo	6.7	4.7	6.2
PSO	2.7	0.7	2.0
SWEPCo	4.3	3.0	3.9

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, 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)(d)	Coal	50.0 %	$ 1,357.4	$ 9.2	$ 905.1
PSO					
North Central Wind Energy Facilities (e)(f)	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 (e)(f)	Wind	54.5 %	1,066.8	10.1	35.2
Total			$ 3,692.8	$ 31.6	$ 1,131.3

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2021 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 377.6	$ 6.3	$ 133.5
Pirkey Plant, Unit 1 (a)	Lignite	85.9 %	613.8	—	528.3
Turk Generating Plant (a)	Coal	73.3 %	1,598.0	10.2	285.6
Total			$ 2,589.4	$ 16.5	$ 947.4
I&M					
Rockport Generating Plant (b)(c)(d)	Coal	50.0 %	$ 1,247.2	$ 13.9	$ 794.5
PSO					
North Central Wind Energy Facilities (e)(f)	Wind	45.5 %	$ 313.7	$ —	$ 4.2
SWEPCo					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 377.6	$ 6.3	$ 133.5
Pirkey Plant, Unit 1 (a)	Lignite	85.9 %	613.8	—	528.3
Turk Generating Plant (a)	Coal	73.3 %	1,598.0	10.2	285.6
North Central Wind Energy Facilities (e)(f)	Wind	54.5 %	376.2	—	5.4
Total			$ 2,965.6	$ 16.5	$ 952.8

(a) Operated by SWEPCo.
(b) Operated by I&M.
(c) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 was subject to a finance lease with a nonaffiliated company. In December 2022, the lease expired at which point I&M and AEGCo acquired 100% of the interests in Unit 2. See the "Rockport Plant Litigation" section of Note 6 for additional information.
(d) AEGCo owns 50%.
(e) PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. Sundance was placed into service in April 2021. Maverick was placed into service in September 2021. Traverse was placed into service in March 2022. See the "Acquisitions" section of Note 7 for additional information.
(f) Operated by PSO.

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, 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.

	Year Ended December 31, 2020						
	Vertically Integrated Utilities	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other**	**Reconciling Adjustments**	**AEP Consolidated**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 3,606.8	$ 2,086.9	$ —	$ —	$ —	$ —	$ 5,693.7
Commercial Revenues	2,016.2	1,048.6	—	—	—	—	3,064.8
Industrial Revenues	2,018.0	390.1	—	—	—	(0.7)	2,407.4
Other Retail Revenues	155.6	42.5	—	—	—	—	198.1
Total Retail Revenues	7,796.6	3,568.1	—	—	—	(0.7)	11,364.0
Wholesale and Competitive Retail Revenues:							
Generation Revenues	588.3	—	—	131.9	—	—	720.2
Transmission Revenues (a)	334.5	467.0	1,257.0	—	—	(1,006.7)	1,051.8
Renewable Generation Revenues (b)	—	—	—	60.9	—	(1.6)	59.3
Retail, Trading and Marketing Revenues (c)	—	—	—	1,486.9	(5.5)	(103.0)	1,378.4
Total Wholesale and Competitive Retail Revenues	922.8	467.0	1,257.0	1,679.7	(5.5)	(1,111.3)	3,209.7
Other Revenues from Contracts with Customers (b)	163.2	157.8	22.4	2.3	92.5	(148.6)	289.6
Total Revenues from Contracts with Customers	8,882.6	4,192.9	1,279.4	1,682.0	87.0	(1,260.6)	14,863.3
Other Revenues:							
Alternative Revenue Programs (d)	(3.2)	70.0	(80.6)	—	—	7.5	(6.3)
Other Revenues (b) (e)	—	83.0	—	43.6	9.8	(74.9)	61.5
Total Other Revenues	(3.2)	153.0	(80.6)	43.6	9.8	(67.4)	55.2
Total Revenues	$ 8,879.4	$ 4,345.9	$ 1,198.8	$ 1,725.6	$ 96.8	$ (1,328.0)	$ 14,918.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $965 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $103 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, 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.

	Year Ended December 31, 2020						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 563.6	$ —	$ 1,250.6	$ 794.1	$ 1,523.4	$ 579.4	$ 630.8
Commercial Revenues	366.7	—	517.0	499.3	682.0	320.1	466.7
Industrial Revenues	120.1	—	553.5	547.4	270.0	221.1	328.8
Other Retail Revenues	29.5	—	67.6	6.6	13.1	66.0	9.1
Total Retail Revenues	1,079.9	—	2,388.7	1,847.4	2,488.5	1,186.6	1,435.4
Wholesale Revenues:							
Generation Revenues (a)	—	—	230.2	274.6	—	15.1	162.0
Transmission Revenues (b)	399.9	1,210.3	130.8	29.0	67.0	27.5	111.2
Total Wholesale Revenues	399.9	1,210.3	361.0	303.6	67.0	42.6	273.2
Other Revenues from Contracts with Customers (c)	48.2	22.4	59.5	85.0	109.5	34.7	26.7
Total Revenues from Contracts with Customers	1,528.0	1,232.7	2,809.2	2,236.0	2,665.0	1,263.9	1,735.3
Other Revenues:							
Alternative Revenue Programs (d)	3.4	(87.0)	(13.0)	5.8	66.6	2.2	3.2
Other Revenues (e)	87.5	—	—	—	17.5	—	—
Total Other Revenues	90.9	(87.0)	(13.0)	5.8	84.1	2.2	3.2
Total Revenues	$ 1,618.9	$ 1,145.7	$ 2,796.2	$ 2,241.8	$ 2,749.1	$ 1,266.1	$ 1,738.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $112 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 $952 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $69 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, 2022. 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	2023	2024-2025	2026-2027	After 2027	Total
			(in millions)		
AEP	$ 85.5	$ 157.3	$ 133.9	$ 60.3	$ 437.0
APCo	16.1	32.2	23.2	11.7	83.2
I&M	4.6	9.2	9.2	4.5	27.5

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, 2022 and 2021.

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, 2022 and 2021.

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, 2022 and 2021. 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,	
Company	**2022**	**2021**
	(in millions)	
AEP Texas	$ 0.1	$ 0.4
AEPTCo	113.8	95.5
APCo	64.5	117.8
I&M	75.3	61.2
OPCo	49.9	51.7
PSO	18.8	18.8
SWEPCo	19.1	24.7

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, 2022 and 2021.

20. GOODWILL

The disclosure in this note applies to AEP only.

AEP's carrying amount of goodwill for the years ended December 31, 2022 and 2021 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2020	$ 37.1	$ 15.4	$ 52.5
Impairment Losses	—	—	—
Balance as of December 31, 2021	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2022	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2022 and 2021, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

21. SUBSEQUENT EVENTS

Planned 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 within the Generation & Marketing segment.

As of December 31, 2022, the competitive contracted renewable portfolio assets totaled 1.4 gigawatts of generation resources representing consolidated solar and wind assets, with a net book value of $1.2 billion, and a 50% interest in four joint venture wind farms, totaling $247 million, accounted for as equity method investments.

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 competitive contracted renewables portfolio and AEP signed an agreement to sell the competitive contracted renewables portfolio to a nonaffiliated party for $1.5 billion including the assumption of project debt. As part of the sale agreement, AEP provided the acquirer an indemnification related to certain losses, not to exceed $70 million, which could result from one of the joint venture wind farm's inability to meet certain minimum performance requirements.

The sale is subject to FERC approval, clearance from the Committee on Foreign Investment in the United States and approval under applicable competition laws. AEP expects to close on the sale in the second quarter of 2023 and receive cash proceeds, net of taxes, transaction fees and other customary closing adjustments, of approximately $1.2 billion.

Management concluded the consolidated assets within the competitive contracted renewables portfolio met the accounting requirements to be presented as Held for Sale in the first quarter of 2023 based on the receipt of final bids, Board of Director approval to consummate a sale transaction and the signing of the sale agreement. AEP anticipates recording an estimated pretax loss ranging from $175 million to $225 million ($100 million to $150 million after-tax), in the first quarter of 2023 as a result of reaching Held for Sale status. Management concluded the impact of any other than temporary decline in the fair value of the four joint venture wind farms was not material to AEP's December 31, 2022 financial statements. Any changes to the book value or carrying value of these assets, or the anticipated sale price, could further reduce future net income and impact financial condition.

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 22, 2023, there were approximately 50,957 registered shareholders and approximately 1,131,149 shareholders holding stock in street name through a bank or broker. There were 514,121,695 shares outstanding as of February 22, 2023.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2022. 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
Julia A. Sloat	53	President and Chief Executive Officer
Nicholas K. Akins	62	Executive Chair of the Board of Directors
Christian T. Beam	54	Executive Vice President - Energy Services
David M. Feinberg	53	Executive Vice President, General Counsel and Secretary
Greg B. Hall	50	Executive Vice President and Chief Commercial Officer
Ann P. Kelly	52	Executive Vice President and Chief Financial Officer
Therace M. Risch	49	Executive Vice President and Chief Information & Technology Officer
Peggy Simmons	45	Executive Vice President - Utilities
Raja Sundararajan	48	Executive Vice President - External Affairs
Phillip R. Ulrich	52	Executive Vice President and Chief Human Resources Officer
Charles E. Zebula	62	Executive Vice President - Portfolio Optimization

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