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

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **March 31, 2022**
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

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

Registrant	Title of each class	Trading Symbol	Name of Each Exchange on Which Registered
American Electric Power Company Inc.	Common Stock, $6.50 par value	AEP	The NASDAQ Stock Market LLC
American Electric Power Company Inc.	6.125% Corporate Units	AEPPZ	The NASDAQ Stock Market LLC

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit such files).
Yes ☒ No ☐

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

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

Smaller reporting company ☐ Emerging growth company ☐

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

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

Smaller reporting company ☐ Emerging growth company ☐

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

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

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

	Number of shares of common stock outstanding of the Registrants as of April 28, 2022
American Electric Power Company, Inc.	513,544,176
	($6.50 par value)
AEP Texas Inc.	100
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	3,680
	($18 par value)

(a) 100% interest is held by AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of American Electric Power Company, Inc.

NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
March 31, 2022

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP 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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AMI	Advanced Metering Infrastructure.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered Expanded Net Energy Cost deferral balance.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
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.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,296 MW nuclear plant owned by I&M.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.

Term	Meaning
CSAPR	Cross-State Air Pollution Rule.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel X, DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV and DCC XVI, consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. DHLC is a non-consolidated VIE of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Equity Units	AEP's Equity Units issued in August 2020 and March 2019.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
KWh	Kilowatt-hour.
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.

Term	Meaning
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,484 MWs of wind generation.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTC	Production Tax Credits.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants:AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated VIE for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.

Term	Meaning
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
Sundance	Sundance, acquired in April 2021 as part of the North Central Wind Energy Facilities, consists of 199 MWs of wind generation in Oklahoma.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA).The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Transition Funding	AEP Texas Central Transition Funding III LLC, a wholly-owned subsidiary of TCC and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Traverse	Traverse, part of the North Central Wind Energy Facilities, consists of 998 MWs of wind generation in Oklahoma.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Part I – Item 2 Management's Discussion and Analysis of Financial Condition and Results of Operations" of this quarterly report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- The impact of pandemics, including COVID-19, and any associated disruption of AEP's business operations due to impacts on economic or market conditions, costs of compliance with potential government regulations and employees' reactions to those regulations, electricity usage, supply chain issues, customers, service providers, vendors and suppliers.
- The economic impact of escalating 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 in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- The availability and cost of funds to finance working capital and capital needs, particularly (i) if expected sources of capital, such as proceeds from the sale of assets or subsidiaries, do not materialize, 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 and government regulation, including changes to tax laws and regulations, oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or PM and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- The risks associated with fuels used before, during and after the generation of electricity, including coal ash and nuclear fuel.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.

- Volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars 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 the 2021 Annual Report and in Part II 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/.

Company Website and Availability of SEC Filings

Our principal corporate website address is www.aep.com. Information on our website is not incorporated by reference herein and is not part of this Form 10-Q. We make available free of charge through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding AEP.

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

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the first quarter of 2022 increased by 3.2% from the first quarter of 2021. Weather-normalized residential sales increased by 0.8% in the first quarter of 2022 from the first quarter of 2021. AEP's first quarter 2022 industrial sales volumes increased by 5.6% compared to the first quarter of 2021. The increase in industrial sales was spread across many industries. Weather-normalized commercial sales increased 4.2% in the first quarter of 2022 from the first quarter of 2021.

COVID-19

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

Regulatory Matters

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

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

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

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

In March 2021, the Virginia SCC issued an order confirming certain decisions from the November 2020 order and rejecting the various requests for reconsideration from APCo and an intervenor. In March 2021, APCo filed a notice of appeal of the reconsideration order with the Virginia Supreme Court. In September 2021, APCo submitted its brief before the Virginia Supreme Court. The brief was in alignment with the previous items of appeal filed by APCo in March 2021. In October 2021, the Virginia SCC and additional intervenors filed briefs with the Virginia Supreme Court disagreeing with the items appealed by APCo in the Triennial Review decision. Additionally, the Virginia SCC and APCo filed briefs disagreeing with the items appealed by an intervenor in a separate appeal of the same decision. In March 2022, oral arguments were held at the Virginia Supreme Court and APCo is currently awaiting the Virginia Supreme Court's decision.

APCo ultimately seeks an increase in base rates through its appeal to the Virginia Supreme Court. Among other issues, this appeal includes APCo's request for proper treatment of the closed coal-fired plant assets in APCo's 2017-2019 triennial period, reducing APCo's earnings below the bottom of its authorized ROE band. If APCo's appeal regarding treatment of the closed coal plants is granted by the Virginia Supreme Court, it could initially reduce future net income and impact financial condition as a consequence of expensing the closed coal-fired plant regulatory asset established as a result of the Virginia SCC's decision in the 2017-2019 Triennial Review. A Virginia Supreme Court decision in favor of APCo's original expensing of the closed coal-fired plant asset balances would likely result in a remand to the Virginia SCC. Upon a subsequent Virginia SCC order, the initial negative impact for the write-off of the closed coal-fired plant asset balances could potentially be offset by an increase in base rates for earning below APCo's 2017-2019 authorized ROE band.

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

  In March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant. In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. SWEPCo disagrees with the Court of Appeals decision and submitted a Petition for Review with the Texas Supreme Court in November 2021. The Texas Supreme Court has requested responses to the Petition for Review, which are due at the end of April 2022.

  If SWEPCo is ultimately unable to recover capitalized Turk Plant costs including 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 $180 million related to revenues collected from February 2013 through March 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 phased out current energy efficiency programs as of December 31, 2020, including OPCo's shared savings revenues of $26 million annually and renewable mandates after 2026. HB 6 also provided for 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 will be allocated to all electric distribution utilities on a non-bypassable basis. OPCo's Inter-Company Power Agreement for OVEC terminates in June 2040. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of the Speaker of the Ohio House of Representatives, Larry Householder, four other individuals, and Generation Now, an entity registered as a 501(c)(4) social welfare organization, in connection with an alleged racketeering conspiracy involving the adoption of HB 6. Certain defendants in that case have since pleaded guilty. In August 2020, an AEP shareholder filed a putative class action lawsuit against AEP and certain of its officers for alleged violations of securities laws in connection with HB 6. In May 2021, the defendants filed a motion to dismiss the securities litigation for failure to state a claim, which was granted with prejudice in December 2021. In addition, four AEP shareholders have 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, rescinded the payments to the nonaffiliated owner of Ohio's nuclear power plants that were previously authorized under HB 6. The new legislation, House Bill 128, went into effect 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 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 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 transmission owning subsidiaries. In its February 2022 order on rehearing, the FERC affirmed the decision in its July 2021 order.

  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 $55 million to $70 million on an annual basis.

- *FERC RTO Incentive Complaint* - In February 2022, the Office of the Ohio Consumer's Council 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 Ohio Consumer's Council 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.Management believes its financial statements adequately address the impact of the February 2022 complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

- *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. LPSC staff testimony is due to the LPSC in May 2022 and an order is expected before the end of 2022. 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 of March 31, 2022, PSO and SWEPCo have deferred regulatory assets of $681 million and $418 million, respectively, relating to natural gas expenses and purchases of electricity incurred from February 9, 2021, to February 20, 2021, as a result of severe winter weather. SWEPCo's deferred regulatory asset consists of $96 million, $141 million and $181 million related to the Arkansas, Louisiana and Texas jurisdictions, respectively.

  In January 2022, PSO, OCC staff and certain intervenors filed a joint stipulation and settlement agreement with the OCC to approve PSO's securitization of the extraordinary fuel and purchases of electricity. The agreement includes a determination that all of PSO's extraordinary fuel and purchases of electricity were prudent and reasonable and a 0.75% carrying charge, subject to true-up based on actual financing costs. In February 2022, the OCC approved the joint stipulation and settlement agreement in its financing order.The issuance of the securitization bonds must be approved by the Supreme Court of Oklahoma. A ruling by the Supreme Court is expected in the second quarter of 2022. PSO expects to complete the securitization process in 2022, subject to market conditions.

  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. SWEPCo is currently recovering the fuel costs at an interim carrying charge of 0.3%.In April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05%, which has been supported by APSC staff. Various other parties have recommended recovery periods ranging from 5-20 years with a carrying charge of 1.65%. SWEPCo is awaiting a decision from the APSC. The prudence of these fuel costs is expected to be addressed in a separate proceeding.

In March 2021, the LPSC approved a special order granting a temporary modification to the FAC 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 net operating loss carryforwards (NOLC) in its PJM and SPP transmission formula rates beginning with the 2022 projected 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 is consistent with recent base rate case filings AEP has made.In those rate cases, inclusion of NOLCs in rates is contingent upon a successful private letter ruling from the IRS.Management believes the financial statements adequately address the impact of its transition to stand-alone treatment of NOLCs in rates.

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		Approved ROE	New Rates Effective
		(in millions)			
SWEPCo	Texas	$ 39.4		9.25%	March 2021
I&M	Indiana	61.4	(a)	9.7%	February 2022

(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	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
			(in millions)		
SWEPCo	Louisiana	December 2020	$ 94.7	10.35%	9.1%-9.8%
SWEPCo	Arkansas	July 2021	80.9	10.35%	8.75%-9.3%
KGPCo	Tennessee	November 2021	6.9	10.2%	7.35%

Dolet Hills Power Station and Related Fuel Operations

In December 2021, the Dolet Hills Power Station was retired.The Dolet Hills Power Station non-fuel costs are recoverable by SWEPCo through base rates and through a rate rider in the Texas jurisdiction. As of March 31, 2022, SWEPCo's share of the net investment in the Dolet Hills Power Station was $108 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 clausesAs of March 31, 2022, SWEPCo had a net under-recovered fuel balance of $84 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Dolet Hills Power Station.Additional reclamation and other land-related costs incurred by DHLC and Oxbow will be billed to SWEPCo and included in existing fuel clauses.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $30 million of additional costs with a recovery period to be determined at a later date. In November 2021, the LPSC issued a directive which deferred the issues regarding modification of the level and timing of recovery of the Dolet Hills Power Station from SWEPCo's pending rate case to a separate existing docket. In addition, the recovery of the deferred fuel costs are planned to be addressed.

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

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

Pirkey Power Plant and Related Fuel Operations

In 2020, management announced plans to retire the Pirkey Power Plant in 2023.The Pirkey Power Plant non-fuel costs are recoverable by SWEPCo through base rates and fuel costs are recovered through active fuel clauses. As of March 31, 2022, SWEPCo's share of the net investment in the Pirkey Power Plant was $207 million, including CWIP, before cost of removal.Sabine is a mining operator providing mining services to the Pirkey Power Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $87 million as of March 31, 2022. As of March 31, 2022, SWEPCo had a net under-recovered fuel balance of $84 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Pirkey Power Plant.Additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in 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. As of March 31, 2022, the competitive contracted renewable portfolio assets totaled 1.6 gigawatts of generation resources representing consolidated solar and wind assets and a 50% interest in five joint venture wind farms accounted for as equity method investments. The anticipated disposition of all or a portion of the AEP Renewables' portfolio has not met the accounting requirements to be presented as Held for Sale as of March 31, 2022.If AEP is unable to recover the book value or carrying value of these assets, it could reduce future net income and impact financial condition.

Regulated Renewable Generation Facilities

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs, o a fixed cost turn-key basis at completion. 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 i Arkansas and Louisiana. The Oklahoma and Louisiana portions of the NCWF revenue requirement, net of PTC benefit, are recoverable through authorized riders beginning at commercial operation and until such time as amounts are reflected in base rates. Recovery of the Arkansas portion of the NCWF revenue requirement is requested in SWEPCo's pending 2021 Arkansas Base Rate Case. The table below provides a summary of the facilities as of March 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	80 %	998

(a) PTC benefits are available for a ten year period following the in-service date.

See "North Central Wind Energy Facilities" section of Note 6 for additional information.

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

In November 2021, PSO issued requests for proposals to acquire up to 2,800 MWs of wind and up to 1,350 MWs of solar generation resources.The wind and solar generation projects would be subject to regulatory approval.

In December 2021, APCo petitioned for approval and cost recovery of a 204 MW wind project and three solar facilities totaling 205 MWs, as well as PPAs for another 89 MWs of solar generation resources. An additional 40 MW of qualifying solar facilities have been contracted for, subject to terms of the Company's tariff. In January 2022, APCo issued additional requests for proposals to acquire up to 1,000 MWs of wind and up to 100 MWs of solar generation resources. In February 2022, APCo issued a separate request for proposal for up to 150 MWs of solar resources in West Virginia in support of WV Senate Bill 583. These wind and solar generation projects would also be subject to regulatory approval.

In March 2022, I&M issued requests for proposals to acquire or contract for resources pursuant to meeting I&M's Integrated Resource Plans, which includes approximately 800 MWs of wind generation resources, 500 MWs of solar generation resources and other supplemental capacity resources, including, but not limited to, standalone storage, emerging technologies, thermal, and other capacity resources. These projects would be subject to regulatory approval.

Disposition of KPCo and KTCo

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

Proposed Operations and Maintenance Agreement and Plant Ownership Agreement

KPCo currently operates and owns a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant with the remaining 50% owned by WPCo. The Stock Purchase Agreement is further contingent upon the issuance by the KPSC, WVPSC and FERC of orders regarding a new propose Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo.

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval of a proposed Mitchell Plant Operations ar Maintenance Agreement and Mitchell Plant Ownership Agreement, pursuant to which WPCo would replace KPCo as the operator of the Mitchel Plant and KPCo employees at the Mitchell Plant would become employees of WPCo. Under this originally proposed Ownership Agreement, WPCo is obligated to purchase KPCo's 50% undivided interest in the Mitchell Plant on December 31, 2028 unless KPCo and WPCo have agreed to retire the Mitchell Plant earlier or, absent such agreement, if WPCo elects prior to December 31, 2027 to retire the Mitchell Plant on December 31, 2028.The Ownership Agreement provides that the purchase price for KPCo's 50% ownership interest in the Mitchell Plant will be determined through the mutual agreement of WPCo and KPCo (subject to approval from the KPSC and WVPSC) or through a fair market valuation determination conducte by independent appraisals, with offsets for estimated decommissioning costs and the cost of ELG investments made by WPCo, if KPCo and WPC are unable to reach agreement as to the purchase price.

In January 2022, intervenor testimony was filed with the KPSC, recommending the KPSC either reject the new proposed Mitchell Plant Ownershi Agreement or approve the agreement with certain modifications including a revision to the buyout provision that would set WPCo's Mitchell Plant purchase price at the greater of fair market value or net book value. The intervenor testimony also recommends the KPSC reject the proposed Mitchell Plant Operations and Maintenance Agreement, which the testimony stated should be modified to remove references to the Mitchell Plant Ownership Agreement. In February 2022, AEP filed rebuttal testimony with the KPSC opposing the intervenor testimony filed in January 2022. AEP's rebuttal testimony also discusses an alternative proposal to the fair market value provision included in the proposed Mitchell Plant Ownership Agreement. Under the alternative proposal, KPCo's and WPCo's interest in the Mitchell Plant would be divided by unit if the plant is not retired before the end of 2028 and a mutual agreement cannot be reached on a buyout price. Under the alternative proposal, mutual agreement on the buyout price or unit disposition would need to be finalized by May 2025, with a division of plant ownership by unit effective January 1, 2029, unless otherwise agreed. In March 2022, a hearing was held on the agreements with the KPSC.Following the hearing, KPCo amended its November 2021 filing with a new version of the Mitchell Plant Ownership Agreement that provided further details about the alternative proposal. As amended, the proposed Mitchell Plant Ownership Agreement creates procedures, subject to all required regulatory approvals, that provide the option for WPCo and KPCo to negotiate a sale of KPCo's interest in the Mitchell Plant to WPCo, split the Mitchell Plant units with additional agreements for KPCo to utiliz WPCo's ELG assets, if necessary, or to agree on the procedures and timetable to retire one or both units. As amended, the proposed Mitchell Plant Ownership Agreement replaced certain aspects of the originally proposed agreement including the buyout provision at fair market value. A hearing on the amended filing was held on March 30, 2022. A decision from the KPSC is expected in the second quarter of 2022.

For the filing at the WVPSC, intervenor testimony filed in March 2022 and briefs filed in April 2022 recommended various clarifying modifications to the Mitchell Ownership Agreement and the Mitchell Operations and Maintenance Agreement. A decision from the WVPSC is expected in the second quarter of 2022.

The KPSC and WVPSC intervened in the FERC proceeding and have recommended that FERC dismiss or reject AEP's request, or defer ruling AEP's request until both the retail commissions have rendered decisions. In

February 2022, AEP filed a motion to withdraw its filing with the FERC, noting that AEP intends to re-file its request after the KPSC and WVPSC have reviewed the agreements.

Transfer of Ownership

In December 2021, Liberty, KPCo and KTCo sought approval from the FERC under Section 203 of the Federal Power Act for the sale. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission and generation 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. Liberty, KPCo and KTCo plan to respond to provide additional information in response to the letter. An order from the FERC is expected on the matter in the second quarter of 2022.

In January 2022, KPCo and Liberty filed a joint application requesting the KPSC authorize the transfer of ownership of KPCo to Liberty. In February 2022, certain intervenors filed testimony recommending that the KPSC not approve the transfer of ownership. If, however, the KPSC does approve the transfer, these intervenors recommend that the KPSC require AEP to compensate KPCo customers $578 million for alleged future increased costs and higher rates that the intervenors claim will exist under Liberty's ownership. AEP disagrees with the recommendation and filed rebuttal testimony in March 2022. AEP has committed to fund, through a reduction in Liberty's purchase price, $20 million of Liberty's commitment to provide $40 million of benefits to KPCo customers in bill reductions to help offset fuel costs. Intervenors also recommended imposing certain conditions on Liberty, including conditions related to recovering certain costs, inter-company agreement filing requirements, KPCo's capital structure and future generation resource planning processes and analyses. In addition, certain intervenors argue that the commission should not approve the new proposed Mitchell Plant Ownership Agreement and Mitchell Plant Operations and Maintenance Agreement, and that deciding the request to transfer ownership of KPCo should be separated from approval of the Mitchell agreements even though such approval is a condition to the transaction closing. AEP also disagrees with this argument. A hearing was held with the KPSC in March 2022. In April 2022, certain intervenors filed briefs with the KPSC in support of their original recommendations, including both recommendations for and against approval of the transfer of KPCo to Liberty. A final order is expected in the second quarter of 2022.

Subject to receipt of regulatory approval and resolution of the Mitchell ownership and operating issues disclosed above, the sale is expected to close in the second quarter of 2022 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction.

AEP expects to receive approximately $1.4 billion in cash, net of taxes and transaction fees. AEP plans to use the proceeds to eliminate forecasted equity needs in 2022 as the company invests in regulated renewables, transmission and other projects. AEP and AEPTCo expect the sale to have a one-time impact on after-tax earnings that is not material.

LITIGATION

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

Rockport Plant Litigation

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

After the litigation proceeded at the district court and 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, with closing to occur as of the end of the Rockport Plant, Unit 2 lease in December 2022. The agreement is subject to customary closing conditions and as of the closing will result in a final settlement of, and release of claims in, the lease litigation. As a result, in May 2021, at the parties' request, the district court entered a stipulation and order dismissing the case without prejudice to plaintiffs asserting their claims in a re-filed action or a new action. The required regulatory approvals at the IURC and FERC have been obtained that would allow the closing to occur as of the end of the lease in December 2022. The IURC order approved a settlement agreement addressing the future use of Rockport Plant, Unit 2 as a capacity and energy resource and associated adjustments to I&M's Indiana retail rates, along with certain other matters. Management believes its financial statements appropriately reflect the resolution of the litigation.

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

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. AEP will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Litigation Related to Ohio House Bill 6 (HB 6)

In 2019, Ohio adopted and implemented HB 6 which benefits OPCo by authorizing rate recovery for certain costs including renewable energy contracts and OVEC's coal-fired generating units. OPCo engaged in lobbying efforts and provided testimony during the legislative process in connection with HB 6. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of an Ohio legislator and associates in connection with an alleged racketeering conspiracy involving the adoption of HB 6. After AEP learned of the criminal allegations against the Ohio legislator and others relating to HB 6, 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 United States District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. The amended complaint 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 United States District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The court has entered a scheduling order in the New York state court derivative action setting a deadline of April 29, 2022 for AEP to file a motion to dismiss the complaint and staying the case other than with respect to briefing the motion to dismiss. 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's motion to dismiss the amended complaint is due May 3, 2022 and discovery is stayed pending the district court's ruling on the motion to dismiss. The Ohio state court derivative action has been stayed until a decision by the federal district court on the motion to dismiss the amended complaint. 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 benefits to AEP from the passage of HB 6 and documents relating to AEP's financial processes and controls. AEP is cooperating fully with the SEC's subpoena. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this inquiry will have a material impact on financial condition, results of operations, or cash flows.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and incurs additional operational costs to comply with environmental control requirements. Additional investments and operational changes will be made in response to existing and anticipated requirements to reduce emissions from fossil generation and in response to rules governing the beneficial use and disposal of coal combustion by-products, clean water and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. Management is engaged in the development of possible future requirements including the items discussed below. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

AEP will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If AEP cannot recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed below will have a material impact on AEP System generating units. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of March 31, 2022, the AEP System owned generating capacity of approximately 25,900 MWs, of which approximately 11,900 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 $325 million to $550 million through 2028.

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

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to NAAQS and the development of SIPs to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under MATS, (d) implementation and review of CSAPR and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil generation under Section 111 of the CAA. Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

National Ambient Air Quality Standards

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

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR) in 2005, which could require power plants and other facilities to install best available retrofit technology to address regional haze in federal parks and other protected areas. CAVR is implemented by the states, through SIPs, or by the Federal EPA, through FIPs.In 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that 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 CircuitManagement cannot predict the outcome of that litigation, although management supports the intrastate trading program as a compliance alternative to source-specific controls and has intervened in the litigation in support of the Federal EPA.

Cross-State Air Pollution Rule

CSAPR is a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on SO_2 and NO_X allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

In January 2021, the Federal EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NO_X budgets in 2021-2024. 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 briefing is underway. 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 2022, the EPA Administrator signed a proposed FIP for 2015 Ozone NAAQS that would further revise the ozone season NO_X budgets under the existing CSAPR program. AEP is evaluating the proposed 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 D.C. Circuit vacated the ACE rule and remanded it to the Federal EPA. Management is unable to predict how the Federal EPA will respond to the court's remand. In October 2021 the United States Supreme Court granted certiorari and combined four separate petitions seeking review of the D.C. Circuit Court decisionsOral arguments were held in February 2022 but management is unable to predict the outcome of that litigation.

In 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. That rule has not been finalized. Management continues to actively monitor these rulemaking activities.

While no federal regulatory requirements to reduce CO_2 emissions are in place, AEP has taken action to reduce and offset CO_2 emissions from its generating fleet. AEP expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. In April 2020, Virginia enacted clean energy legislation to allow the state to participate in the Regional Greenhouse Gas Initiative, require the retirement of all fossil-fueled generation by 2045 and require 100% renewable energy to be provided to Virginia customers by 2050. Management is taking steps to comply with these requirements, including increasing wind and solar installations, purchasing renewable power and broadening AEP System's portfolio of energy efficiency programs.

In February 2021, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, grid reliability and resiliency, regulations and the company's current business strategy. The intermediate goal is an 80% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is net-zero CO_2 emissions from AEP generating facilities by 2050. AEP's total estimated CO_2 emissions in 2021 were approximately 50 million metric tons, a 70% reduction from AEP's 2000 CO_2 emissions. AEP has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

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

Coal Combustion Residual Rule

The Federal EPA's CCR rule regulates the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers.

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

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

Company	Plant Name and Unit	Generating Capacity	Net Book Value (a)		Projected Retirement Date
		(in MWs)	(in millions)		
AEGCo	Rockport Plant, Unit 1	655	$ 227.4		2028
APCo	Amos	2,930	2,096.4		2040
APCo	Mountaineer	1,320	968.2		2040
I&M	Rockport Plant, Unit 1	655	492.9	(b)	2028
KPCo	Mitchell Plant	780	584.9		2040
SWEPCo	Flint Creek Plant	258	263.6		2038
WPCo	Mitchell Plant	780	586.5		2040

(a) Net book value before cost of removal including CWIP and inventory.
(b) Amount includes a $165 million regulatory asset related to the retired Tanners Creek Plant. The IURC and MPSC authorized recovery of the Tanners Creek Plant regulatory asset over the useful life of Rockport Plant, Unit 1 in 2015 and 2014, respectively.

In addition, AGR owns Cardinal Plant, Unit 1 a competitive generation unit. A nonaffiliated electric cooperative owns Cardinal Plant, Unit 2 and Unit 3 and operates all three units at the Cardinal Plant. The nonaffiliate filed an application for additional time to develop alternative disposal capacity for the Cardinal Plant. As of March 31, 2022, the net book value of Cardinal Plant, Unit 1, including materials and supplies and CWIP, was approximately $47 million.

In January 2022, the Federal EPA began responding to applications for extension requests and has proposed to deny several extension requests based on allegations that the utilities that received such responses are not in compliance with the CCR Rule.The Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements.The 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. While the Federal EPA has not yet proposed any action on pending extension requests submitted by AEP, statements made by the Federal EPA in proposed denials of extension requests submitted by other utilities indicate that there is a risk that the Federal EPA may similarly conclude that AEP is not eligible for an extension of time to cease use of its CCR impoundments and/or that one or more of AEP's facilities is not in compliance with the CCR RuleIf 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 impoundments in Kentucky, Ohio, Virginia and West Virginia that have already been closed in accordance with state law programs or could require AEP to incur costs related to CCR impoundments at various 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 related to competitive units or in regulated jurisdictions without providing similar assurances of cost recovery, it would impose significant additional operating costs on AEP, which could 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 Power Plant and cease using coal at the Welsh Plant:

Company	Plant Name and Unit	Generating Capacity	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Projected Retirement Date
		(in MWs)	(in millions)		
SWEPCo	Pirkey Power Plant	580	$ 99.6	$ 107.7	2023 (b)
SWEPCo	Welsh Plants, Units 1 and 3	1,053	467.2	55.7	2028 (c)(d)

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

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 late 2022. 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 August 2021, the Federal EPA and the Army Corps of Engineers announced their plan to reconsider and revise the Navigable Waters Protection Rule, which defines "waters of the United States" under the Clean Water Act. Shortly thereafter, the United States District Court for the District of Arizona vacated and remanded the Navigable Waters Protection Rule, which had the effect of reinstating the prior, much broader, version of the rule. Because the scope of waters subject to the Federal EPA and Army Corps of Engineers jurisdictions is broader under the prior rule, permitting decisions made in recent years are subject to reevaluation; permits may now be necessary where none were previously required, and issued permits may need to be reopened to impose additional obligations. In December 2021, the Federal EPA proposed a rule that would roll back the definition of "waters of the United States" to the pre-2015 definition. The Federal EPA also announced that it would be considering further changes through a future rulemaking, which would build upon the foundation of the proposed rule. Management will continue to monitor rulemaking on this issue.

In January 2022, the U.S. Supreme Court announced that it would hear an appeal related to the scope of "waters of the United States," specifically whether wetlands can be regulated as waters of the United States. Management cannot predict the outcome of that litigation.

CCR and ELG Compliance Plan Filings

Mitchell Plant (Applies to AEP)

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

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

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval of a proposed Mitchell Plant Operations ar Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo would replace KPCo as th operator of the Mitchell Plant. In February 2022, AEP filed a motion to withdraw its filing with the FERC, noting that AEP intends to re-file its request after the KPSC and WVPSC have reviewed the agreements. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

As of March 31, 2022, the Mitchell Plant ELG investment balance in CWIP was $8 million split equally between KPCo and WPCo. As of March 31, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $585 million.

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

Amos and Mountaineer Plants (Applies to AEP and APCo)

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

In August 2021, the Virginia SCC issued an order approving APCo's request to construct CCR-related investments at the Amos and Mountaineer Plants and approved recovery of CCR-related other operation and maintenance expenses and investments through an active rider.The order denied APCo's request to construct the ELG investments and denied recovery of previously incurred ELG costsIn March 2022, APCo refiled for approval of the ELG investments and previously incurred ELG costs.A hearing is scheduled to take place in September 2022 and an order is anticipated in the fourth quarter of 2022.

Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approve recovery of the West Virginia jurisdictional share of these costs through an active rider. In October 2021, due to the Virginia SCC previously rejecting the ELG investments, the WVPSC issued an order directing APCo to proceed with CCR/ELG compliance plans that would allow the plants t continue operating beyond 2028. The October order further states that APCo will not share capacity and energy from the plants with customers from Virginia if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plants to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that APCo will be given the opportunity to recover, from West Virginia customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plants beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred.In October and November 2021, intervenors filed petitions for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

APCo expects total Amos and Mountaineer Plant ELG investment, excluding AFUDC, to be approximately $197 millionAs of March 31, 2022, APCo's Virginia jurisdictional share of the net book value, before cost of removal including CWIP and inventory, of the Amos and Mountaineer Plants was approximately $1.5 billion and APCo's Virginia jurisdictional share of its ELG investment balance in CWIP for these plants was $41 million.

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

Impact of Environmental Regulation on Coal-Fired Generation

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal, 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 Unit 2, Dolet Hills Power Station and Northeastern Plant Unit 3.

The table below summarizes the net book value, as of March 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	$ 159.1	$ 132.5	2026	(c)	$ 14.9
SWEPCo	Dolet Hills Power Station	—	72.2	2021	(d)	—
SWEPCo	Pirkey Power Plant	99.6	107.7	2023	(e)	13.4
SWEPCo	Welsh Plant, Units 1 and 3	467.2	55.7	2028 (f)	(g)	37.3
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) Dolet Hills Power Station is currently being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Arkansas and Texas jurisdictions. 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) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and 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) Welsh Plant, Unit 2 is being recovered over the blended useful life of Welsh Plant, Units 1 and 3.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets 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.

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

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(in millions)	
Vertically Integrated Utilities	$ 298.2	$ 270.4
Transmission and Distribution Utilities	152.8	114.4
AEP Transmission Holdco	173.1	172.0
Generation & Marketing	114.2	36.6
Corporate and Other	(23.6)	(18.4)
Earnings Attributable to AEP Common Shareholders	$ 714.7	$ 575.0

AEP CONSOLIDATED

First Quarter of 2022 Compared to First Quarter of 2021

Earnings Attributable to AEP Common Shareholders increased from $575 million in 2021 to $715 million in 2022 primarily due to:

- Favorable rate proceedings in AEP's various jurisdictions.
- Increased weather-normalized sales volumes.
- Favorable mark-to-market economic hedge activity driven by higher commodity prices.

These increases were partially offset by:

- A decrease in unrealized gains on AEP's investment in ChargePoint.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended March 31, 2022	2021
	(in millions)	
Revenues	$ 2,687.4	$ 2,537.3
Fuel and Purchased Electricity	866.1	859.0
Gross Margin	1,821.3	1,678.3
Other Operation and Maintenance	769.2	740.2
Depreciation and Amortization	500.0	432.1
Taxes Other Than Income Taxes	125.2	123.5
Operating Income	426.9	382.5
Other Income	5.2	0.7
Allowance for Equity Funds Used During Construction	8.1	9.9
Non-Service Cost Components of Net Periodic Benefit Cost	27.6	17.0
Interest Expense	(151.0)	(139.6)
Income Before Income Tax Expense (Benefit) and Equity Earnings	316.8	270.5
Income Tax Expense (Benefit)	17.9	(0.2)
Equity Earnings of Unconsolidated Subsidiary	0.3	0.7
Net Income	299.2	271.4
Net Income Attributable to Noncontrolling Interests	1.0	1.0
Earnings Attributable to AEP Common Shareholders	$ 298.2	$ 270.4

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2022	2021
	(in millions of KWhs)	
Retail:		
Residential	9,225	9,481
Commercial	5,518	5,258
Industrial	8,162	7,702
Miscellaneous	544	519
Total Retail	23,449	22,960
Wholesale (a)	4,474	4,642
Total KWhs	27,923	27,602

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended March 31,	
	2022	2021
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,590	1,539
Normal – Heating (b)	1,604	1,600
Actual – Cooling (c)	2	3
Normal – Cooling (b)	4	4
Western Region		
Actual – Heating (a)	915	958
Normal – Heating (b)	871	866
Actual – Cooling (c)	20	26
Normal – Cooling (b)	28	28

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

First Quarter of 2022 Compared to First Quarter of 2021

Reconciliation of First Quarter of 2021 to First Quarter of 2022
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

First Quarter of 2021	$	270.4
Changes in Gross Margin:		
Retail Margins		139.2
Margins from Off-system Sales		(17.1)
Transmission Revenues		14.0
Other Revenues		6.9
Total Change in Gross Margin		143.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(29.0)
Depreciation and Amortization		(67.9)
Taxes Other Than Income Taxes		(1.7)
Other Income		4.5
Allowance for Equity Funds Used During Construction		(1.8)
Non-Service Cost Components of Net Periodic Pension Cost		10.6
Interest Expense		(11.4)
Total Change in Expenses and Other		(96.7)
Income Tax Expense		(18.1)
Equity Earnings of Unconsolidated Subsidiary		(0.4)
First Quarter of 2022	$	298.2

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 $139 million primarily due to the following:
  - A $47 million increase at APCo and WPCo due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - A $35 million increase in weather-normalized retail margins primarily in the commercial and industrial classes.
  - A $27 million increase at PSO primarily due to a $15 million increase in rider revenues and a $12 million increase in base rate revenues. These increases were partially offset in other expense items below.
  - A $20 million increase at I&M primarily due to an increase in rider revenues and a prior year provision for refund. This increase was partially offset in other expense items below.
  - A $10 million increase at SWEPCo primarily due to a base rate revenue increase in Texas and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $4 million increase due to lower customer refunds related to Tax Reform primarily at APCo and WPCo.This increase was partially offset in Income Tax Expense below.

  These increases were partially offset by:
  - A $21 million decrease at SWEPCo in municipal and cooperative revenues primarily due to the February 2021 severe winter weather event.
- **Margins from Off-system Sales** decreased $17 million primarily due to Turk Plant merchant sales in February 2021 at SWEPCo as a result of the severe winter weather event.

- **Transmission Revenues** increased $14 million primarily due to continued investment in transmission assets.
- **Other Revenues** increased $7 million primarily due to the sale of emission allowances at I&M. This increase is offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses increased $29 million primarily due to the following:
  - A $52 million increase in PJM transmission services. This increase was partially offset in Retail Margins above.
  - A $5 million increase in SPP transmission services.
  - A $4 million increase in customer accounts due to bad debt write-offs and factoring.

  These increases were partially offset by:
  - A $35 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 is offset in Depreciation and Amortization expense below.
- **Depreciation and Amortization** expenses increased $68 million primarily due to the following:
  - A $39 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 expense above.
  - A $23 million increase due to a higher depreciable base at APCo, I&M and SWEPCo and the implementation of increased Texas depreciation rates at SWEPCo.
- **Other Income** increased $5 million primarily due to carrying charges on regulatory assets at PSO and SWEPCo resulting from the February 2021 severe winter weather event.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $11 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 $11 million primarily due to higher long-term debt balances at PSO and SWEPCo.
- **Income Tax Expense** increased $18 million primarily due to an increase in pretax income, a decrease in amortization of Excess ADIT and a decrease in parent company loss benefit, partially offset by an increase in PTC. The decrease in amortization of Excess ADIT is partially offset above in Retail Margins.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(in millions)	
Revenues	$ 1,246.8	$ 1,088.1
Purchased Electricity	232.6	205.5
Gross Margin	1,014.2	882.6
Other Operation and Maintenance	428.5	365.2
Depreciation and Amortization	183.6	172.7
Taxes Other Than Income Taxes	164.4	157.6
Operating Income	237.7	187.1
Interest and Investment Income	0.2	0.4
Carrying Costs Income	0.1	0.5
Allowance for Equity Funds Used During Construction	7.3	6.8
Non-Service Cost Components of Net Periodic Benefit Cost	11.9	7.3
Interest Expense	(74.8)	(74.5)
Income Before Income Tax Expense	182.4	127.6
Income Tax Expense	29.6	13.2
Net Income	152.8	114.4
Net Income Attributable to Noncontrolling Interests	—	—
Earnings Attributable to AEP Common Shareholders	$ 152.8	$ 114.4

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(in millions of KWhs)	
Retail:		
Residential	6,977	6,924
Commercial	5,999	5,576
Industrial	5,930	5,281
Miscellaneous	171	166
Total Retail (a)	19,077	17,947
Wholesale (b)	571	603
Total KWhs	19,648	18,550

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

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

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

	Three Months Ended March 31,	
	2022	**2021**
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,864	1,777
Normal – Heating (b)	1,886	1,883
Actual – Cooling (c)	1	—
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	278	315
Normal – Heating (b)	190	185
Actual – Cooling (d)	88	137
Normal – Cooling (b)	126	126

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

First Quarter of 2022 Compared to First Quarter of 2021

Reconciliation of First Quarter of 2021 to First Quarter of 2022
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

First Quarter of 2021	$	114.4
Changes in Gross Margin:		
Retail Margins		111.0
Margins from Off-system Sales		12.7
Transmission Revenues		24.1
Other Revenues		(16.2)
Total Change in Gross Margin		131.6
Changes in Expenses and Other:		
Other Operation and Maintenance		(63.3)
Depreciation and Amortization		(10.9)
Taxes Other Than Income Taxes		(6.8)
Interest and Investment Income		(0.2)
Carrying Costs Income		(0.4)
Allowance for Equity Funds Used During Construction		0.5
Non-Service Cost Components of Net Periodic Benefit Cost		4.6
Interest Expense		(0.3)
Total Change in Expenses and Other		(76.8)
Income Tax Expense		(16.4)
First Quarter of 2022	$	152.8

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 $111 million primarily due to the following:
  - A $42 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $25 million increase in weather-normalized retail margins primarily in the commercial class partially offset in the industrial class.
  - A $17 million increase due to prior year refunds of Excess ADIT to customers in Texas. This increase was offset in Income Tax Expense below.
  - A $14 million increase from interim rate increases driven by increased distribution and transmission investment in Texas.
  - A $12 million increase related to various rider revenues in Ohio. This increase was partially offset in Margins from Off-system Sales, Other Revenues and other expense items below.
  - A $6 million increase in revenue from rate riders in Texas. This increase was partially offset in other expense items below.
- **Margins from Off-system Sales** increased $13 million primarily due to an increase in off-system sales at OVEC in Ohio driven by higher market prices. This increase was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** increased $24 million primarily due to the following:
  - A $17 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $4 million increase due to prior year refunds to customers associated with the most recent base rate case in Texas. This increase was offset in Other Revenues below.

- **Other Revenues** decreased $16 million primarily due to the following:
  - An $8 million decrease primarily due to prior year refunds to customers associated with the most recent base rate case in Texas. This decrease was partially offset in Retail Margins and Transmission Revenues above.
  - An $8 million decrease primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs in Ohio. This decrease was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $63 million primarily due to the following:
  - A $34 million increase in transmission expenses in Ohio primarily due to a $36 million increase in recoverable PJM expenses partially offset by a $4 million decrease in transmission formula rate true-up activity. The recoverable PJM expenses were partially offset in Retail Margins above.
  - A $9 million increase in employee-related expenses.
  - A $6 million increase in vegetation management expenses.
  - A $6 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.
  - A $5 million increase in factored customer accounts receivable expenses in Ohio primarily due to bad debt expenses and a prior year adjustment to allowance for doubtful accounts.
- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base of transmission and distribution assets in Texas.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to increased property taxes driven by additional investments in transmission and distribution assets and higher tax rates in Ohio.
- **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.
- **Income Tax Expense** increased $16 million primarily due to an increase in pretax book income and a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was partially offset in Gross Margin above.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended March 31, 2022	2021
	(in millions)	
Transmission Revenues	$ 411.4	$ 377.0
Other Operation and Maintenance	31.7	27.2
Depreciation and Amortization	85.3	72.7
Taxes Other Than Income Taxes	67.3	59.2
Operating Income	227.1	217.9
Interest and Investment Income	0.1	0.2
Allowance for Equity Funds Used During Construction	15.6	16.7
Non-Service Cost Components of Net Periodic Benefit Cost	1.3	0.5
Interest Expense	(39.1)	(35.3)
Income Before Income Tax Expense and Equity Earnings	205.0	200.0
Income Tax Expense	50.4	45.8
Equity Earnings of Unconsolidated Subsidiary	19.1	19.0
Net Income	173.7	173.2
Net Income Attributable to Noncontrolling Interests	0.6	1.2
Earnings Attributable to AEP Common Shareholders	$ 173.1	$ 172.0

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	March 31, 2022	2021
	(in millions)	
Plant in Service	$ 11,870.9	$ 10,549.3
Construction Work in Progress	1,633.9	1,635.9
Accumulated Depreciation and Amortization	861.1	648.1
Total Transmission Property, Net	$ 12,643.7	$ 11,537.1

First Quarter of 2022 Compared to First Quarter of 2021

Reconciliation of First Quarter of 2021 to First Quarter of 2022
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

First Quarter of 2021	$	172.0
Changes in Transmission Revenues:		
Transmission Revenues		34.4
Total Change in Transmission Revenues		34.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(4.5)
Depreciation and Amortization		(12.6)
Taxes Other Than Income Taxes		(8.1)
Interest and Investment Income		(0.1)
Allowance for Equity Funds Used During Construction		(1.1)
Non-Service Cost Components of Net Periodic Pension Cost		0.8
Interest Expense		(3.8)
Total Change in Expenses and Other		(29.4)
Income Tax Expense		(4.6)
Equity Earnings of Unconsolidated Subsidiary		0.1
Net Income Attributable to Noncontrolling Interests		0.6
First Quarter of 2022	$	173.1

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

- **Transmission Revenues** increased $34 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $5 million primarily due to an increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $13 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $5 million primarily due to an increase in pretax book income and a decrease in parent company loss benefit.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended March 31, 2022	2021
	(in millions)	
Revenues	$ 619.3	$ 634.2
Fuel, Purchased Electricity and Other	448.1	565.9
Gross Margin	171.2	68.3
Other Operation and Maintenance	32.5	28.2
Depreciation and Amortization	23.3	18.6
Taxes Other Than Income Taxes	3.1	2.6
Operating Income	112.3	18.9
Interest and Investment Income	2.1	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	5.1	3.8
Interest Expense	(5.0)	(3.3)
Income Before Income Tax Benefit and Equity Earnings (Loss)	114.5	19.9
Income Tax Benefit	(6.7)	(15.1)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(5.2)	3.2
Net Income	116.0	38.2
Net Income Attributable to Noncontrolling Interests	1.8	1.6
Earnings Attributable to AEP Common Shareholders	$ 114.2	$ 36.6

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended March 31, 2022	2021
	(in millions of MWhs)	
Fuel Type:		
Coal	1	1
Renewables	1	1
Total MWhs	2	2

First Quarter of 2022 Compared to First Quarter of 2021

Reconciliation of First Quarter of 2021 to First Quarter of 2022
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

First Quarter of 2021	$	36.6
Changes in Gross Margin:		
Merchant Generation		(19.2)
Renewable Generation		5.6
Retail, Trading and Marketing		116.5
Total Change in Gross Margin		102.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(4.3)
Depreciation and Amortization		(4.7)
Taxes Other Than Income Taxes		(0.5)
Interest and Investment Income		1.6
Non-Service Cost Components of Net Periodic Benefit Cost		1.3
Interest Expense		(1.7)
Total Change in Expenses and Other		(8.3)
Income Tax Benefit		(8.4)
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(8.4)
Net Income Attributable to Noncontrolling Interests		(0.2)
First Quarter of 2022	$	114.2

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

- **Merchant Generation** decreased $19 million primarily due to increased outage days at Cardinal Plant and the sale of certain merchant generation assets in 2021, partially offset by higher market prices.
- **Renewable Generation** increased $6 million primarily due to new wind and solar projects placed in service.
- **Retail, Trading and Marketing** increased $117 million primarily due to higher mark-to-market economic hedge activity driven by higher commodity prices.

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

- **Other Operation and Maintenance** expenses increased $4 million primarily due to the following:
  - A $3 million increase related to bad debt expense adjustments.
  - A $2 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $5 million primarily due to a higher depreciable base from increased investments in renewable energy sources.
- **Income Tax Benefit** decreased $8 million primarily due to an increase in pretax book income, partially offset by an increase in PTC, a favorable discrete tax adjustment and a decrease in state income taxes.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $8 million primarily due to lower revenues driven by lower wind production from jointly owned assets.

CORPORATE AND OTHER

First Quarter of 2022 Compared to First Quarter of 2021

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $18 million in 2021 to a loss of $24 million in 2022 primarily due to:

- A $16 million decrease due to lower unrealized gains relating in an investment in ChargePoint.
- A $10 million decrease primarily due to a favorable bad debt expense adjustment in 2021.
- A $9 million increase in interest expense due to higher long-term and short-term debt balances.
- An $8 million decrease in interest income due to a lower return on investments held by EIS.
- A $3 million increase in transaction costs due to the anticipated sale of the Kentucky operations.

These items were partially offset by:

- A $49 million decrease in Income Tax Expense primarily due to the following:
  - A $27 million decrease due to a consolidating tax adjustment.
  - An $11 million decrease due to a decrease in pretax book income.
  - A $10 million decrease due to an increase in parent company loss benefit.

AEP SYSTEM INCOME TAXES

First Quarter of 2022 Compared to First Quarter of 2021

Income Tax Expense decreased $2 million primarily due to an increase in pretax book income, partially offset by an increase in PTC and a decrease in state income taxes.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	March 31, 2022		December 31, 2021	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 33,864.1	55.3 %	$ 33,454.5	57.0 %
Short-term Debt	3,380.3	5.5	2,614.0	4.4
Total Debt	37,244.4	60.8	36,068.5	61.4
AEP Common Equity	23,791.3	38.8	22,433.2	38.2
Noncontrolling Interests	246.8	0.4	247.0	0.4
Total Debt and Equity Capitalization	$ 61,282.5	100.0 %	$ 58,748.7	100.0 %

AEP's ratio of debt-to-total capital decreased from 61.4% as of December 31, 2021 to 60.8% as of March 31, 2022 primarily due to an increase in earnings in 2022 in addition to the settlement of the forward equity purchase contracts related to the 2019 Equity Units, partially offset by an increase in debt to support distribution, transmission and renewable investment growth. See "Equity Units" section of Note 12 for additional information.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity. As of March 31, 2022, AEP had $5 billion of revolving credit facilities to support its commercial paper program. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, leasing agreements, hybrid securities or common stock. In February 2021, severe winter weather impacted certain AEP service territories resulting in disruptions to SPP market conditions. In March 2021, AEP entered into a $500 million 364-day Term Loan and borrowed the full amount to help address the cash flow implications resulting from the February 2021 severe winter weather event. In February 2022, AEP entered into a $250 million Term Loan, maturing in September 2022, for general corporate business purposes, including the pay down of short-term debt. In March 2022, AEP extended the maturity date of the original 364-Day Term Loan to August 2022. See Note 4 - Rate Matters for additional information.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of March 31, 2022, available liquidity was approximately $3.8 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)
	Term Loan (b)	500.0	August 2022	
	Term Loan	250.0	September 2022	
Cash and Cash Equivalents		675.6		
Total Liquidity Sources		6,425.6		
Less:	AEP Commercial Paper Outstanding	1,880.3		
	Term Loan (b)	500.0		
	Term Loan	250.0		
Net Available Liquidity		$ 3,795.3		

(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.

(b) In March 2022, AEP extended the maturity date of the original 364-Day Term Loan to August 2022.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during the first three months of 2022 was $2.4 billion. The weighted-average interest rate for AEP's commercial paper during 2022 was 0.69%.

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 $400 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2022 was $309 million with maturities ranging from April 2022 to March 2023.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility which expire in September 2023 and 2024, respectively. As of March 31, 2022, the affiliated utility subsidiaries are in compliance with all requirements under the agreement.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of March 31, 2022, this contractually-defined percentage was 57.8%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

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

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

ATM Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, up to an aggregate of $1 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 three months ended March 31, 2022. As of March 31, 2022, approximately $511 million of equity is available for issuance under the ATM offering program. See Note 12 - Financing Activities for additional information.

Equity Units

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

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes due in 2024 and a forward equity purchase contract which 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 12 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.78 per share in April 2022.Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 12 for additional information.

Credit Ratings

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

CASH FLOW

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

	Three Months Ended March 31, 2022	2021
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 451.4	$ 438.3
Net Cash Flows from (Used for) Operating Activities	1,622.2	(117.2)
Net Cash Flows Used for Investing Activities	(2,893.2)	(1,634.2)
Net Cash Flows from Financing Activities	1,545.1	1,637.1
Net Increase (Decrease) in Cash and Cash Equivalents	274.1	(114.3)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 725.5	$ 324.0

Operating Activities

	Three Months Ended March 31, 2022	2021
	(in millions)	
Net Income	$ 718.1	$ 578.8
Non-Cash Adjustments to Net Income (a)	766.6	762.7
Mark-to-Market of Risk Management Contracts	282.3	21.0
Property Taxes	(82.0)	(74.8)
Deferred Fuel Over/Under-Recovery, Net	(148.8)	(1,225.1)
Change in Other Noncurrent Assets	26.5	(168.9)
Change in Other Noncurrent Liabilities	36.9	83.5
Change in Certain Components of Working Capital	22.6	(94.4)
Net Cash Flows from (Used for) Operating Activities	$ 1,622.2	$ (117.2)

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

Net Cash Flows from (Used for) Operating Activities increased by $1.7 billion primarily due to the following:

- A $1.1 billion increase in cash primarily due to fuel and purchased power expenses incurred in 2021 as a result of the February 2021 severe winter weather event in SPP impacting PSO and SWEPCo. PSO and SWEPCo are working with their respective regulatory commissions to determine the recovery period from customers as well as the appropriate carrying charge on the regulatory assets. See Note 4 - Rate Matters for additional information.
- A $261 million increase primarily due to collateral held against risk management contracts due to pricing movement in the commodities market.
- A $195 million increase in cash from changes in Noncurrent 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. KPCo intends to seek recovery of these

incremental storm costs in their next base rate case while APCo is expected to seek recovery in separate filings. In October 2021, SWEPCo requested recovery of these storm costs, in addition to storm costs from Hurricanes Delta and Laura, in a filing with the LPSC.See Note 4 - Rate Matters for additional information.

- A $143 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $117 million increase in cash from the Change in Certain Components of Working Capital. The increase is primarily due to a return of margin deposits from PJM originally paid in 2021 and a decrease in employee-related payments, partially offset by a decrease due to the timing of accounts payable.

Investing Activities

	Three Months Ended March 31,			
	2022		2021	
	(in millions)			
Construction Expenditures	$	(1,686.6)	$	(1,492.7)
Acquisitions of Nuclear Fuel		(31.1)		(55.9)
Acquisition of the Dry Lake Solar Project		—		(102.9)
Acquisition of the North Central Wind Energy Facilities		(1,207.3)		—
Other		31.8		17.3
Net Cash Flows Used for Investing Activities	$	(2,893.2)	$	(1,634.2)

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

- A $1.1 billion increase due to the acquisition of the North Central Wind Energy Facilities in 2022, partially offset by the acquisition of the Dry Lake Solar Project in 2021. See Note 6 - Acquisitions, Assets and Liabilities Held for Sale for additional information.
- A $194 million increase in construction expenditures, primarily due to increases in Vertically Integrated Utilities of $129 million and Transmission and Distribution Utilities of $72 million.

Financing Activities

	Three Months Ended March 31,			
	2022		2021	
	(in millions)			
Issuance of Common Stock	$	809.5	$	184.6
Issuance/Retirement of Debt, Net		1,214.9		1,869.9
Dividends Paid on Common Stock		(398.8)		(372.0)
Other		(80.5)		(45.4)
Net Cash Flows from Financing Activities	$	1,545.1	$	1,637.1

Net Cash Flows from Financing Activities decreased by $92 million primarily due to the following:

- A $1.5 billion decrease in issuances of long-term debt. See Note 12 - Financing Activities for additional information.

This decrease in cash was partially offset by:

- A $625 million increase in issuances of common stock primarily due to the settlement of the 2019 equity units. See “Equity Units” section of Note 12 for additional information.
- A $600 million decrease in retirements of long-term debt. See Note 12 - Financing Activities for additional information.
- A $197 million increase due to changes in short-term debt. See Note 12 - Financing Activities for additional information.

See the “Long-term Debt Subsequent Events” section of Note 12 for Long-term debt and other securities issued, retired and principal payments made after March 31, 2022 through April 28, 2022, the date that the first quarter 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.6 billion of capital expenditures in 2022. For the four year period, 2023 through 2026, management forecasts capital expenditures of $30.7 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 and 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. For complete information of forecasted capital expenditures, see the “Budgeted Capital Expenditures” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2021 Annual Report.

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2021 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the “Cash Flow” section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the “Critical Accounting Policies and Estimates” section of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2021 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting standards.

ACCOUNTING STANDARDS

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

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

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.This segment is exposed to certain market risks as a marketer of wholesale and retail electricity.

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

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Chief Operating Officer, Executive Vice President of Generation, Senior Vice President of Grid Solutions, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Senior Vice President of Treasury and Risk and Chief Risk Officer in addition to Energy Supply's President and Senior Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The effects of COVID-19 continue to be monitored, and while markets have shown improvement, credit risks remain as counterparties encounter business and supply chain disruptions.

Due to multiple defaults of market participants, ERCOT 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. Financial costs associated with securitization are allocated to certain market participants and in that role AEPEP is exposed, but not materially. If the market rules were to change on how socialized losses are allocated this could affect AEPEP's exposure.Regardless of the approach of how socialized losses are allocated there are potential downstream impacts that could push counterparties into financial distress and or bankruptcy, affecting AEPEP, AEP Texas and ETT.

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

MTM Risk Management Contract Net Assets (Liabilities)
Three Months Ended March 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	(59.4)	1.5	(15.7)	(73.6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	0.8	0.8
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	132.5	132.5
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	29.3	24.0	—	53.3
MTM Risk Management Contract Net Assets Held for Sale Related to KPCo (d)	4.3	—	—	4.3
Total MTM Risk Management Contract Net Assets (Liabilities) as of March 31, 2022	$ 34.0	$ (65.9)	$ 393.5	361.6
Commodity Cash Flow Hedge Contracts				511.6
Interest Rate Cash Flow Hedge Contracts				3.8
Fair Value Hedge Contracts				(81.7)
Collateral Deposits				(654.2)
Total MTM Derivative Contract Net Assets as of March 31, 2022				$ 141.1

(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.
(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 6 for additional information.

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

Credit Risk

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

AEP has risk management contracts (includes non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of March 31, 2022, credit exposure net of collateral to sub investment grade counterparties was approximately 0.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of March 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	$ 659.1	$ 208.3	$ 450.8	3	$ 203.5
Split Rating	0.1	—	0.1	1	0.1
Noninvestment Grade	0.1	0.1	—	—	—
No External Ratings:					
Internal Investment Grade	54.9	—	54.9	3	43.3
Internal Noninvestment Grade	9.8	7.3	2.5	3	2.5
Total as of March 31, 2022	$ 724.0	$ 215.7	$ 508.3		

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 March 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

Three Months Ended March 31, 2022				Twelve Months Ended December 31, 2021			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.1	$ 1.3	$ 0.5	$ 0.1	$ 0.4	$ 3.6	$ 0.4	$ 0.1

VaR Model
Non-Trading Portfolio

Three Months Ended March 31, 2022				Twelve Months Ended December 31, 2021			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 12.0	$ 16.6	$ 11.5	$ 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. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the three months ended March 31, 2022 and 2021, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $37 million and $40 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended March 31,	
	2022	2021
REVENUES		
Vertically Integrated Utilities	$ 2,646.8	$ 2,504.5
Transmission and Distribution Utilities	1,242.2	1,082.3
Generation & Marketing	609.5	601.7
Other Revenues	94.1	92.6
TOTAL REVENUES	4,592.6	4,281.1
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,500.7	1,560.7
Other Operation	662.2	592.4
Maintenance	285.0	274.9
Depreciation and Amortization	792.4	696.3
Taxes Other Than Income Taxes	364.2	346.5
TOTAL EXPENSES	3,604.5	3,470.8
OPERATING INCOME	988.1	810.3
Other Income (Expense):		
Other Income	2.3	21.7
Allowance for Equity Funds Used During Construction	31.0	33.4
Non-Service Cost Components of Net Periodic Benefit Cost	47.2	29.6
Interest Expense	(313.4)	(290.2)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	755.2	604.8
Income Tax Expense	52.8	54.5
Equity Earnings of Unconsolidated Subsidiaries	15.7	28.5
NET INCOME	718.1	578.8
Net Income Attributable to Noncontrolling Interests	3.4	3.8
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 714.7	$ 575.0
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	506,050,147	497,058,635
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.41	$ 1.16
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	507,658,522	498,164,219
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.41	$ 1.15

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Net Income	$ 718.1	$ 578.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $65.9 and $15.0 in 2022 and 2021, Respectively	248.0	56.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.6) and $(0.5) in 2022 and 2021, Respectively,	(2.2)	(2.0)
TOTAL OTHER COMPREHENSIVE INCOME	245.8	54.3
TOTAL COMPREHENSIVE INCOME	963.9	633.1
Total Comprehensive Income Attributable To Noncontrolling Interests	3.4	3.8
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 960.5	$ 629.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2020	516.8	$ 3,359.3	$ 6,588.9	$ 10,687.8	$ (85.1)	$ 223.6	$ 20,774.5
Issuance of Common Stock	2.7	17.1	167.5				184.6
Common Stock Dividends				(369.5) (a)		(2.5)	(372.0)
Other Changes in Equity			(21.9)	(0.6)		3.4	(19.1)
Acquisition of Dry Lake Solar Project						18.9	18.9
Net Income				575.0		3.8	578.8
Other Comprehensive Income					54.3		54.3
TOTAL EQUITY – MARCH 31, 2021	519.5	$ 3,376.4	$ 6,734.5	$ 10,892.7	$ (30.8)	$ 247.2	$ 21,220.0
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	0.4	2.4	807.1				809.5
Common Stock Dividends				(395.2) (a)		(3.6)	(398.8)
Other Changes in Equity			(15.2)	(1.5)		—	(16.7)
Net Income				714.7		3.4	718.1
Other Comprehensive Income					245.8		245.8
TOTAL EQUITY – MARCH 31, 2022	524.8	$ 3,411.1	$ 7,964.5	$ 11,985.1	$ 430.6	$ 246.8	$ 24,038.1

(a) Cash dividends declared per AEP common share were $0.78 and $0.74 for the three months ended March 31, 2022 and 2021.

ondensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

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

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 675.6	$ 403.4
Restricted Cash (March 31, 2022 and December 31, 2021 Amounts Include $49.9 and $48, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)	49.9	48.0
Other Temporary Investments (March 31, 2022 and December 31, 2021 Amounts Include $203.3 and $214.8, Respectively, Related to EIS and Transource Energy)	208.5	220.4
Accounts Receivable:		
Customers	743.1	720.9
Accrued Unbilled Revenues	205.8	204.4
Pledged Accounts Receivable – AEP Credit	990.2	1,038.0
Miscellaneous	51.9	33.9
Allowance for Uncollectible Accounts	(54.4)	(55.6)
Total Accounts Receivable	1,936.6	1,941.6
Fuel	270.4	307.9
Materials and Supplies	696.4	681.3
Risk Management Assets	310.7	194.4
Accrued Tax Benefits	67.5	121.5
Regulatory Asset for Under-Recovered Fuel Costs	840.7	647.8
Assets Held for Sale	2,972.6	2,919.7
Prepayments and Other Current Assets	239.1	323.2
TOTAL CURRENT ASSETS	8,268.0	7,809.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,386.6	23,088.1
Transmission	30,305.9	29,911.1
Distribution	24,759.2	24,440.0
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	5,756.0	5,682.9
Construction Work in Progress	3,967.3	3,684.3
Total Property, Plant and Equipment	89,175.0	86,806.4
Accumulated Depreciation and Amortization	21,297.0	20,805.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	67,878.0	66,001.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,087.6	4,142.3
Securitized Assets	527.6	552.8
Spent Nuclear Fuel and Decommissioning Trusts	3,678.4	3,867.0
Goodwill	52.5	52.5
Long-term Risk Management Assets	260.8	267.0
Operating Lease Assets	646.2	578.3
Deferred Charges and Other Noncurrent Assets	4,432.3	4,398.3
TOTAL OTHER NONCURRENT ASSETS	13,685.4	13,858.2
TOTAL ASSETS	$ 89,831.4	$ 87,668.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2022 and December 31, 2021
(in millions, except per-share and share amounts)
(Unaudited)

			March 31, 2022	December 31, 2021
CURRENT LIABILITIES				
Accounts Payable			$ 1,694.3	$ 2,054.6
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit			750.0	750.0
Other Short-term Debt			2,630.3	1,864.0
Total Short-term Debt			3,380.3	2,614.0
Long-term Debt Due Within One Year (March 31, 2022 and December 31, 2021 Amounts Include $238.4 and $190.5, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			3,008.4	2,153.8
Risk Management Liabilities			130.0	75.4
Customer Deposits			356.2	321.6
Accrued Taxes			1,485.2	1,586.4
Accrued Interest			339.1	273.2
Obligations Under Operating Leases			95.0	97.6
Liabilities Held for Sale			1,873.7	1,880.9
Other Current Liabilities			1,206.4	1,369.2
TOTAL CURRENT LIABILITIES			13,568.6	12,426.7
NONCURRENT LIABILITIES				
Long-term Debt (March 31, 2022 and December 31, 2021 Amounts Include $743.5 and $840.5, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			30,855.7	31,300.7
Long-term Risk Management Liabilities			300.4	230.3
Deferred Income Taxes			8,324.9	8,202.5
Regulatory Liabilities and Deferred Investment Tax Credits			8,486.6	8,686.3
Asset Retirement Obligations			2,750.0	2,676.2
Employee Benefits and Pension Obligations			315.3	328.4
Obligations Under Operating Leases			563.3	492.8
Deferred Credits and Other Noncurrent Liabilities			573.4	601.3
TOTAL NONCURRENT LIABILITIES			52,169.6	52,518.5
TOTAL LIABILITIES			65,738.2	64,945.2
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards			55.1	43.3
TOTAL MEZZANINE EQUITY			55.1	43.3
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2022	**2021**		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	524,777,416	524,416,175		
(11,233,240 Shares and 20,204,160 Shares were Held in Treasury as of March 31, 2022 and December 31, 2021, Respectively)			3,411.1	3,408.7
Paid-in Capital			7,964.5	7,172.6
Retained Earnings			11,985.1	11,667.1
Accumulated Other Comprehensive Income (Loss)			430.6	184.8
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			23,791.3	22,433.2
Noncontrolling Interests			246.8	247.0
TOTAL EQUITY			24,038.1	22,680.2
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$ 89,831.4	$ 87,668.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
OPERATING ACTIVITIES		
Net Income	$ 718.1	$ 578.8
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	792.4	696.3
Rockport Rent, Unit 2 Operating Lease Amortization	—	32.8
Deferred Income Taxes	(17.7)	44.3
Allowance for Equity Funds Used During Construction	(31.0)	(33.4)
Mark-to-Market of Risk Management Contracts	282.3	21.0
Amortization of Nuclear Fuel	22.9	22.7
Property Taxes	(82.0)	(74.8)
Deferred Fuel Over/Under-Recovery, Net	(148.8)	(1,225.1)
Change in Other Noncurrent Assets	26.5	(168.9)
Change in Other Noncurrent Liabilities	36.9	83.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(24.3)	(12.9)
Fuel, Materials and Supplies	27.6	39.5
Accounts Payable	(1.0)	171.8
Accrued Taxes, Net	(51.8)	(80.8)
Other Current Assets	133.9	(26.3)
Other Current Liabilities	(61.8)	(185.7)
Net Cash Flows from (Used for) Operating Activities	1,622.2	(117.2)
INVESTING ACTIVITIES		
Construction Expenditures	(1,686.6)	(1,492.7)
Purchases of Investment Securities	(508.5)	(337.6)
Sales of Investment Securities	497.4	325.5
Acquisitions of Nuclear Fuel	(31.1)	(55.9)
Acquisition of the Dry Lake Solar Project	—	(102.9)
Acquisition of the North Central Wind Energy Facilities	(1,207.3)	—
Other Investing Activities	42.9	29.4
Net Cash Flows Used for Investing Activities	(2,893.2)	(1,634.2)
FINANCING ACTIVITIES		
Issuance of Common Stock	809.5	184.6
Issuance of Long-term Debt	499.6	1,951.5
Issuance of Short-term Debt with Original Maturities greater than 90 Days	271.0	644.2
Change in Short-term Debt with Original Maturities less than 90 Days, Net	710.3	16.9
Retirement of Long-term Debt	(51.0)	(650.7)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(215.0)	(92.0)
Principal Payments for Finance Lease Obligations	(14.7)	(15.0)
Dividends Paid on Common Stock	(398.8)	(372.0)
Other Financing Activities	(65.8)	(30.4)
Net Cash Flows from Financing Activities	1,545.1	1,637.1
Net Increase (Decrease) in Cash and Cash Equivalents	274.1	(114.3)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	451.4	438.3
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 725.5	$ 324.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 233.9	$ 220.5
Net Cash Paid (Received) for Income Taxes	6.9	(0.2)
Noncash Acquisitions Under Finance Leases	7.2	9.0
Construction Expenditures Included in Current Liabilities as of March 31,	758.6	762.7
Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31,	—	6.7
Noncontrolling Interest Assumed - Dry Lake Solar Project	—	18.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2022	2021
	(in millions of KWhs)	
Retail:		
Residential	2,843	2,818
Commercial	2,148	2,074
Industrial	2,427	1,880
Miscellaneous	141	137
Total Retail	7,559	6,909

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

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2022	2021
	(in degree days)	
Actual – Heating (a)	278	315
Normal – Heating (b)	190	185
Actual – Cooling (c)	88	137
Normal – Cooling (b)	126	126

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

First Quarter of 2022 Compared to First Quarter of 2021

AEP Texas Inc. and Subsidiaries
Reconciliation of First Quarter of 2021 to First Quarter of 2022
Net Income
(in millions)

First Quarter of 2021	$	46.1
Changes in Revenues:		
Retail Revenues		39.4
Transmission Revenues		21.1
Other Revenues		(8.0)
Total Change in Revenues		52.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(7.1)
Depreciation and Amortization		(11.3)
Taxes Other Than Income Taxes		(1.0)
Interest Income		(0.1)
Allowance for Equity Funds Used During Construction		0.2
Non-Service Cost Components of Net Periodic Benefit Cost		1.4
Interest Expense		(2.5)
Total Change in Expenses and Other		(20.4)
Income Tax Expense		(8.6)
First Quarter of 2022	$	69.6

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

- **Retail Revenues** increased $39 million primarily due to the following:
  - A $17 million increase due to prior year refunds of Excess ADIT to customers. This increase was offset in Income Tax Expense below.
  - An $8 million increase from interim rate increases driven by increased distribution investment.
  - A $6 million increase from interim rate increases driven by increased transmission investment.
  - A $6 million increase in revenue from rate riders. This increase was partially offset in other expense items below.
  - A $6 million increase in weather-normalized revenues primarily in the residential and commercial classes.

  These increases were partially offset by:
  - A $4 million decrease in weather-related usage primarily due to a 36% decrease in cooling degree days.
- **Transmission Revenues** increased $21 million primarily due to the following:
  - A $17 million increase from interim rate increases driven by increased transmission investment.
  - A $4 million increase due to prior year refunds to customers associated with the most recent base rate case. This increase was offset in Other Revenues below.
- **Other Revenues** decreased $8 million primarily due to prior year refunds to customers associated with the most recent base rate case. This decrease was partially offset in Retail Revenues and Transmission Revenues above.

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

- **Other Operation and Maintenance** expenses increased $7 million primarily due to the following:
  - A $3 million increase in vegetation management expenses.
  - A $3 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base of transmission and distribution assets.
- **Income Tax Expense** increased $9 million primarily due to an increase in pretax book income and a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset above in Retail Revenues.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	2021
REVENUES		
Electric Transmission and Distribution	$ 414.7	$ 361.7
Sales to AEP Affiliates	0.9	1.0
Other Revenues	1.1	1.5
TOTAL REVENUES	416.7	364.2
EXPENSES		
Other Operation	125.8	122.2
Maintenance	22.6	19.1
Depreciation and Amortization	108.8	97.5
Taxes Other Than Income Taxes	37.3	36.3
TOTAL EXPENSES	294.5	275.1
OPERATING INCOME	122.2	89.1
Other Income (Expense):		
Interest Income	0.1	0.2
Allowance for Equity Funds Used During Construction	4.3	4.1
Non-Service Cost Components of Net Periodic Benefit Cost	4.2	2.8
Interest Expense	(45.5)	(43.0)
INCOME BEFORE INCOME TAX EXPENSE	85.3	53.2
Income Tax Expense	15.7	7.1
NET INCOME	$ 69.6	$ 46.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
Net Income	$ 69.6	$ 46.1
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 in 2022 and 2021, Respectively	0.3	0.3
TOTAL COMPREHENSIVE INCOME	$ 69.9	$ 46.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 1,457.9	$ 1,757.0	$ (8.9)	$ 3,206.0
Net Income		46.1		46.1
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	$ 1,457.9	$ 1,803.1	$ (8.6)	$ 3,252.4
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 1,553.9	$ 2,046.8	$ (6.5)	$ 3,594.2
Net Income		69.6		69.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2022	$ 1,553.9	$ 2,116.4	$ (6.2)	$ 3,664.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (March 31, 2022 and December 31, 2021 Amounts Include $39.9 and $30.4, Respectively, Related to Transition Funding and Restoration Funding)	39.9	30.4
Advances to Affiliates	6.8	6.9
Accounts Receivable:		
Customers	149.4	123.4
Affiliated Companies	6.1	7.9
Accrued Unbilled Revenues	73.9	77.9
Miscellaneous	0.1	—
Allowance for Uncollectible Accounts	(4.1)	(4.0)
Total Accounts Receivable	225.4	205.2
Materials and Supplies	78.8	73.9
Risk Management Assets	0.2	—
Accrued Tax Benefits	16.3	24.8
Prepayments and Other Current Assets	16.8	5.9
TOTAL CURRENT ASSETS	384.3	347.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	5,963.6	5,849.9
Distribution	4,995.4	4,917.2
Other Property, Plant and Equipment	982.7	961.1
Construction Work in Progress	586.0	551.3
Total Property, Plant and Equipment	12,527.7	12,279.5
Accumulated Depreciation and Amortization	1,685.6	1,644.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,842.1	10,635.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	277.7	275.2
Securitized Assets (March 31, 2022 and December 31, 2021 Amounts Include $348.9 and $367.6, Respectively, Related to Transition Funding and Restoration Funding)	348.9	367.6
Deferred Charges and Other Noncurrent Assets	289.6	211.3
TOTAL OTHER NONCURRENT ASSETS	916.2	854.1
TOTAL ASSETS	$ 12,142.6	$ 11,836.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ 262.2	$ 26.9
Accounts Payable:		
General	237.3	306.3
Affiliated Companies	30.2	32.5
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2022 and December 31, 2021 Amounts Include $91.3 and $91, Respectively, Related to Transition Funding and Restoration Funding)	841.3	716.0
Accrued Taxes	122.7	93.3
Accrued Interest (March 31, 2022 and December 31, 2021 Amounts Include $2.7 and $2.3, Respectively, Related to Transition Funding and Restoration Funding)	59.0	44.7
Obligations Under Operating Leases	14.0	14.0
Other Current Liabilities	113.8	78.0
TOTAL CURRENT LIABILITIES	1,680.5	1,311.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (March 31, 2022 and December 31, 2021 Amounts Include $302.2 and $313.7, Respectively, Related to Transition Funding and Restoration Funding)	4,329.3	4,464.8
Deferred Income Taxes	1,096.2	1,088.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,248.6	1,242.0
Obligations Under Operating Leases	58.5	61.3
Deferred Credits and Other Noncurrent Liabilities	65.4	73.8
TOTAL NONCURRENT LIABILITIES	6,798.0	6,930.8
TOTAL LIABILITIES	8,478.5	8,242.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,553.9	1,553.9
Retained Earnings	2,116.4	2,046.8
Accumulated Other Comprehensive Income (Loss)	(6.2)	(6.5)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,664.1	3,594.2
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,142.6	$ 11,836.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 69.6	$ 46.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	108.8	97.5
Deferred Income Taxes	7.0	1.7
Allowance for Equity Funds Used During Construction	(4.3)	(4.1)
Mark-to-Market of Risk Management Contracts	(0.2)	—
Property Taxes	(79.5)	(71.1)
Change in Other Noncurrent Assets	(17.0)	(14.8)
Change in Other Noncurrent Liabilities	5.8	14.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(20.2)	(6.8)
Materials and Supplies	(4.9)	0.3
Accounts Payable	9.6	1.4
Accrued Taxes, Net	37.9	34.1
Other Current Assets	0.8	0.3
Other Current Liabilities	16.5	(15.2)
Net Cash Flows from Operating Activities	129.9	84.1
INVESTING ACTIVITIES		
Construction Expenditures	(356.6)	(295.1)
Change in Advances to Affiliates, Net	0.1	0.3
Other Investing Activities	13.7	17.0
Net Cash Flows Used for Investing Activities	(342.8)	(277.8)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	235.3	216.9
Retirement of Long-term Debt – Nonaffiliated	(11.4)	(11.2)
Principal Payments for Finance Lease Obligations	(1.7)	(1.7)
Other Financing Activities	0.2	0.3
Net Cash Flows from Financing Activities	222.4	204.3
Net Increase in Cash, Cash Equivalents and Restricted Cash	9.5	10.6
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	30.5	28.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 40.0	$ 39.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 29.9	$ 30.0
Noncash Acquisitions Under Finance Leases	0.6	0.8
Construction Expenditures Included in Current Liabilities as of March 31,	147.6	120.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of March 31, 2022	2021
	(in millions)	
Plant In Service	$ 11,466.5	$ 10,144.5
Construction Work in Progress	1,527.8	1,549.5
Accumulated Depreciation and Amortization	830.5	623.6
Total Transmission Property, Net	$ 12,163.8	$ 11,070.4

First Quarter of 2022 Compared to First Quarter of 2021

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of First Quarter of 2021 to First Quarter of 2022
Net Income
(in millions)

First Quarter of 2021	$ 151.7
Changes in Transmission Revenues:	
Transmission Revenues	38.7
Total Change in Transmission Revenues	38.7
Changes in Expenses and Other:	
Other Operation and Maintenance	(4.1)
Depreciation and Amortization	(12.5)
Taxes Other Than Income Taxes	(7.8)
Allowance for Equity Funds Used During Construction	(1.1)
Interest Expense	(3.6)
Total Change in Expenses and Other	(29.1)
Income Tax Expense	(5.9)
First Quarter of 2022	$ 155.4

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

- **Transmission Revenues** increased $39 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $4 million primarily due to an increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $13 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $6 million primarily due to an increase in pretax book income and a decrease in parent company loss benefit.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
REVENUES		
Transmission Revenues	$ 75.7	$ 76.0
Sales to AEP Affiliates	324.7	285.6
Other Revenues	—	0.1
TOTAL REVENUES	400.4	361.7
EXPENSES		
Other Operation	25.5	21.1
Maintenance	3.3	3.6
Depreciation and Amortization	83.1	70.6
Taxes Other Than Income Taxes	65.6	57.8
TOTAL EXPENSES	177.5	153.1
OPERATING INCOME	222.9	208.6
Other Income (Expense):		
Interest Income - Affiliated	0.1	0.1
Allowance for Equity Funds Used During Construction	15.6	16.7
Interest Expense	(37.7)	(34.1)
INCOME BEFORE INCOME TAX EXPENSE	200.9	191.3
Income Tax Expense	45.5	39.6
NET INCOME	$ 155.4	$ 151.7

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2020	$ 2,765.6	$ 1,947.3	$ 4,712.9
Capital Contribution from Member	124.0		124.0
Net Income		151.7	151.7
TOTAL MEMBER'S EQUITY – MARCH 31, 2021	$ 2,889.6	$ 2,099.0	$ 4,988.6
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2021	$ 2,949.6	$ 2,426.5	$ 5,376.1
Dividends Paid to Member		(40.0)	(40.0)
Net Income		155.4	155.4
TOTAL MEMBER'S EQUITY – MARCH 31, 2022	$ 2,949.6	$ 2,541.9	$ 5,491.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Advances to Affiliates	$ 3.1	$ 27.2
Accounts Receivable:		
Customers	29.5	22.5
Affiliated Companies	110.6	96.1
Total Accounts Receivable	140.1	118.6
Materials and Supplies	10.1	9.3
Assets Held for Sale	169.9	167.9
Prepayments and Other Current Assets	2.4	8.3
TOTAL CURRENT ASSETS	325.6	331.3
TRANSMISSION PROPERTY		
Transmission Property	11,037.6	10,886.3
Other Property, Plant and Equipment	428.9	427.4
Construction Work in Progress	1,527.8	1,394.8
Total Transmission Property	12,994.3	12,708.5
Accumulated Depreciation and Amortization	830.5	772.8
TOTAL TRANSMISSION PROPERTY – NET	12,163.8	11,935.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	6.4	8.5
Deferred Property Taxes	214.4	245.7
Deferred Charges and Other Noncurrent Assets	4.2	3.2
TOTAL OTHER NONCURRENT ASSETS	225.0	257.4
TOTAL ASSETS	$ 12,714.4	$ 12,524.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ 322.2	$ 124.0
Accounts Payable:		
General	295.9	460.1
Affiliated Companies	77.2	69.9
Long-term Debt Due Within One Year – Nonaffiliated	104.0	104.0
Accrued Taxes	420.2	479.0
Accrued Interest	48.3	28.4
Obligations Under Operating Leases	1.1	0.9
Liabilities Held for Sale	27.6	27.6
Other Current Liabilities	19.3	3.0
TOTAL CURRENT LIABILITIES	1,315.8	1,296.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,240.5	4,239.9
Deferred Income Taxes	990.0	962.9
Regulatory Liabilities	660.5	644.1
Obligations Under Operating Leases	1.9	1.3
Deferred Credits and Other Noncurrent Liabilities	14.2	3.2
TOTAL NONCURRENT LIABILITIES	5,907.1	5,851.4
TOTAL LIABILITIES	7,222.9	7,148.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	2,949.6	2,949.6
Retained Earnings	2,541.9	2,426.5
TOTAL MEMBER'S EQUITY	5,491.5	5,376.1
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,714.4	$ 12,524.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	2021
OPERATING ACTIVITIES		
Net Income	$ 155.4	$ 151.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	83.1	70.6
Deferred Income Taxes	23.1	8.3
Allowance for Equity Funds Used During Construction	(15.6)	(16.7)
Property Taxes	31.3	30.0
Change in Other Noncurrent Assets	2.1	1.4
Change in Other Noncurrent Liabilities	11.8	0.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(21.8)	(16.5)
Materials and Supplies	(0.8)	(0.3)
Accounts Payable	3.6	(18.9)
Accrued Taxes, Net	(53.7)	(35.1)
Accrued Interest	20.4	24.3
Other Current Assets	0.5	0.9
Other Current Liabilities	(0.6)	1.4
Net Cash Flows from Operating Activities	238.8	201.7
INVESTING ACTIVITIES		
Construction Expenditures	(417.1)	(400.5)
Change in Advances to Affiliates, Net	22.6	3.0
Other Investing Activities	(1.7)	(0.8)
Net Cash Flows Used for Investing Activities	(396.2)	(398.3)
FINANCING ACTIVITIES		
Capital Contributions from Member	—	124.0
Change in Advances from Affiliates, Net	197.4	72.6
Dividends Paid to Member	(40.0)	—
Net Cash Flows from Financing Activities	157.4	196.6
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 16.4	$ 8.9
Construction Expenditures Included in Current Liabilities as of March 31,	214.6	244.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(in millions of KWhs)	
Retail:		
Residential	3,532	3,695
Commercial	1,519	1,457
Industrial	2,219	2,078
Miscellaneous	213	200
Total Retail	7,483	7,430
Wholesale	363	948
Total KWhs	7,846	8,378

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

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(in degree days)	
Actual – Heating (a)	1,274	1,284
Normal – Heating (b)	1,319	1,315
Actual – Cooling (c)	2	4
Normal – Cooling (b)	6	6

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

First Quarter of 2022 Compared to First Quarter of 2021

Appalachian Power Company and Subsidiaries
Reconciliation of First Quarter of 2021 to First Quarter of 2022
Net Income
(in millions)

First Quarter of 2021	$	122.5
Changes in Gross Margin:		
Retail Margins		70.0
Margins from Off-system Sales		(1.5)
Transmission Revenues		4.0
Other Revenues		1.3
Total Change in Gross Margin		73.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(43.4)
Depreciation and Amortization		(9.4)
Taxes Other Than Income Taxes		(2.5)
Interest Income		(0.2)
Allowance for Equity Funds Used During Construction		(1.5)
Non-Service Cost Components of Net Periodic Benefit Cost		2.6
Interest Expense		0.6
Total Change in Expenses and Other		(53.8)
Income Tax Expense		(22.3)
First Quarter of 2022	$	120.2

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 $70 million primarily due to the following:
  - A $45 million increase due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - A $16 million increase in weather-normalized margins primarily in the residential and commercial classes.
  - A $10 million increase due to lower customer refunds related to Tax Reform. This increase was partially offset in Income Tax Expense below.
- **Transmission Revenues** increased $4 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $43 million primarily due to the following:
  - A $43 million increase in recoverable PJM transmission expenses. This increase was partially offset in Retail Margins above.
  - A $7 million increase in maintenance expenses at various generation plants.

These increases were partially offset by:

  - A $4 million decrease in transmission formula rate true-up activity. This decrease was partially offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base.
- **Income Tax Expense** increased $22 million primarily due to a decrease in amortization of Excess ADIT, an increase in pretax book income and a decrease in parent company loss benefit. The decrease in amortization of Excess ADIT was partially offset in Retail Margins above.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	2021
REVENUES		
Electric Generation, Transmission and Distribution	$ 847.1	$ 764.2
Sales to AEP Affiliates	56.9	50.1
Other Revenues	3.3	2.7
TOTAL REVENUES	907.3	817.0
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	60.7	163.9
Purchased Electricity for Resale	209.8	90.1
Other Operation	184.9	150.4
Maintenance	74.1	65.2
Depreciation and Amortization	145.2	135.8
Taxes Other Than Income Taxes	40.2	37.7
TOTAL EXPENSES	714.9	643.1
OPERATING INCOME	192.4	173.9
Other Income (Expense):		
Interest Income	0.1	0.3
Allowance for Equity Funds Used During Construction	2.0	3.5
Non-Service Cost Components of Net Periodic Benefit Cost	7.3	4.7
Interest Expense	(54.3)	(54.9)
INCOME BEFORE INCOME TAX EXPENSE	147.5	127.5
Income Tax Expense	27.3	5.0
NET INCOME	$ 120.2	$ 122.5

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
Net Income	$ 120.2	$ 122.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(0.1) and $2.4 in 2022 and 2021, Respectively	(0.2)	9.0
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.3) and $(0.3) in 2022 and 2021, Respectively	(1.1)	(1.1)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(1.3)	7.9
TOTAL COMPREHENSIVE INCOME	$ 118.9	$ 130.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2020	$ 260.4	$ 1,828.7	$ 2,248.0	$ 7.2	$ 4,344.3
Common Stock Dividends			(12.5)		(12.5)
Net Income			122.5		122.5
Other Comprehensive Income				7.9	7.9
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2021	$ 260.4	$ 1,828.7	$ 2,358.0	$ 15.1	$ 4,462.2
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2021	$ 260.4	$ 1,828.7	$ 2,534.4	$ 24.4	$ 4,647.9
Common Stock Dividends			(18.8)		(18.8)
Net Income			120.2		120.2
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2022	$ 260.4	$ 1,828.7	$ 2,635.8	$ 23.1	$ 4,748.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6.0	$ 2.5
Restricted Cash for Securitized Funding	10.0	17.6
Advances to Affiliates	19.7	20.8
Accounts Receivable:		
Customers	142.7	158.5
Affiliated Companies	76.4	129.9
Accrued Unbilled Revenues	51.9	54.0
Miscellaneous	0.5	0.2
Allowance for Uncollectible Accounts	(2.1)	(1.6)
Total Accounts Receivable	269.4	341.0
Fuel	48.4	67.1
Materials and Supplies	109.0	109.8
Risk Management Assets	7.0	42.0
Regulatory Asset for Under-Recovered Fuel Costs	301.6	201.3
Margin Deposits	10.5	71.8
Prepayments and Other Current Assets	28.4	51.4
TOTAL CURRENT ASSETS	810.0	925.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,697.1	6,683.9
Transmission	4,363.2	4,322.4
Distribution	4,729.9	4,683.3
Other Property, Plant and Equipment	699.1	696.6
Construction Work in Progress	530.4	469.9
Total Property, Plant and Equipment	17,019.7	16,856.1
Accumulated Depreciation and Amortization	5,146.4	5,051.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,873.3	11,804.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	733.9	757.6
Securitized Assets	178.8	185.1
Employee Benefits and Pension Assets	224.2	220.5
Operating Lease Assets	63.8	66.9
Deferred Charges and Other Noncurrent Assets	140.3	129.2
TOTAL OTHER NONCURRENT ASSETS	1,341.0	1,359.3
TOTAL ASSETS	$ 14,024.3	$ 14,088.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2022 and December 31, 2021
(Unaudited)

	March 31, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 35.5	$ 199.3
Accounts Payable:		
General	254.4	262.2
Affiliated Companies	118.8	118.6
Long-term Debt Due Within One Year – Nonaffiliated	480.9	480.7
Customer Deposits	75.1	73.9
Accrued Taxes	125.0	119.7
Accrued Interest	79.0	47.9
Obligations Under Operating Leases	14.9	15.1
Other Current Liabilities	90.5	98.5
TOTAL CURRENT LIABILITIES	1,274.1	1,415.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,446.3	4,458.2
Deferred Income Taxes	1,819.0	1,804.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,210.3	1,238.8
Asset Retirement Obligations	402.5	394.9
Employee Benefits and Pension Obligations	40.9	41.5
Obligations Under Operating Leases	49.4	52.4
Deferred Credits and Other Noncurrent Liabilities	33.8	34.6
TOTAL NONCURRENT LIABILITIES	8,002.2	8,025.1
TOTAL LIABILITIES	9,276.3	9,441.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	2,635.8	2,534.4
Accumulated Other Comprehensive Income (Loss)	23.1	24.4
TOTAL COMMON SHAREHOLDER'S EQUITY	4,748.0	4,647.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 14,024.3	$ 14,088.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 120.2	$ 122.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	145.2	135.8
Deferred Income Taxes	4.1	(1.7)
Allowance for Equity Funds Used During Construction	(2.0)	(3.5)
Mark-to-Market of Risk Management Contracts	34.3	12.1
Deferred Fuel Over/Under-Recovery, Net	(100.3)	(6.4)
Change in Other Noncurrent Assets	1.4	(54.3)
Change in Other Noncurrent Liabilities	(20.4)	6.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	72.4	25.1
Fuel, Materials and Supplies	19.5	25.2
Margin Deposits	61.4	(5.2)
Accounts Payable	33.6	46.0
Accrued Taxes, Net	26.1	8.2
Other Current Assets	2.3	1.6
Other Current Liabilities	18.3	3.1
Net Cash Flows from Operating Activities	416.1	315.3
INVESTING ACTIVITIES		
Construction Expenditures	(233.9)	(187.5)
Change in Advances to Affiliates, Net	1.1	(239.7)
Other Investing Activities	9.7	6.6
Net Cash Flows Used for Investing Activities	(223.1)	(420.6)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	494.3
Change in Advances from Affiliates, Net	(163.8)	(18.6)
Retirement of Long-term Debt – Nonaffiliated	(12.7)	(362.5)
Principal Payments for Finance Lease Obligations	(2.0)	(1.9)
Dividends Paid on Common Stock	(18.8)	(12.5)
Other Financing Activities	0.2	0.2
Net Cash Flows from (Used for) Financing Activities	(197.1)	99.0
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(4.1)	(6.3)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	20.1	22.7
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 16.0	$ 16.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 21.0	$ 28.9
Noncash Acquisitions Under Finance Leases	0.3	0.4
Construction Expenditures Included in Current Liabilities as of March 31,	94.9	96.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2022	2021
	(in millions of KWhs)	
Retail:		
Residential	1,539	1,532
Commercial	1,119	1,078
Industrial	1,790	1,802
Miscellaneous	16	17
Total Retail	4,464	4,429
Wholesale	1,957	1,945
Total KWhs	6,421	6,374

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

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2022	2021
	(in degree days)	
Actual – Heating (a)	2,240	2,056
Normal – Heating (b)	2,171	2,170
Actual – Cooling (c)	—	—
Normal – Cooling (b)	1	1

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

First Quarter of 2022 Compared to First Quarter of 2021

Indiana Michigan Power Company and Subsidiaries
Reconciliation of First Quarter of 2021 to First Quarter of 2022
Net Income
(in millions)

First Quarter of 2021	$	70.8
Changes in Gross Margin:		
Retail Margins		31.8
Margins from Off-system Sales		0.7
Transmission Revenues		1.6
Other Revenues		(1.0)
Total Change in Gross Margin		33.1
Changes in Expenses and Other:		
Other Operation and Maintenance		13.3
Depreciation and Amortization		(25.7)
Taxes Other Than Income Taxes		1.0
Other Income		(0.4)
Non-Service Cost Components of Net Periodic Benefit Cost		2.2
Interest Expense		(3.0)
Total Change in Expenses and Other		(12.6)
Income Tax Expense		(1.8)
First Quarter of 2022	$	89.5

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 $32 million primarily due to the following:
  - A $20 million increase primarily due to an increase in rider revenues and a prior year provision for refund. This increase was partially offset in other expense items below.
  - A $7 million increase in weather-normalized retail margins primarily in commercial and industrial classes.
  - A $5 million increase in weather-related usage primarily due to a 9% increase in heating degree days.
- **Other Revenues** decreased $1 million primarily due to a $5 million decrease in barging revenues by River Transportation Division (RTD), partially offset by a $4 million increase due to the sale of allowances. The decrease in RTD barging revenues was partially offset in Other Operation and Maintenance expenses below and the increase due to the sale of emission allowances was partially offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses decreased $13 million primarily due to the following:
  - A $17 million decrease in steam generation expenses primarily 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. This decrease was partially offset in Depreciation Expense below.
  - A $5 million decrease in nonutility operation expenses primarily due to a decrease in RTD expenses. This decrease was partially offset in Other Revenues above.
  - A $4 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2022.

  These decreases were partially offset by:
  - A $7 million increase in transmission expenses primarily due to a $10 million increase in recoverable PJM expenses partially offset by a $2 million decrease in formula rate true up activity. The increase in recoverable PJM expenses was partially offset in Retail Margins above.

- A $3 million increase in nuclear expenses at the Cook Plant primarily due to various maintenance activities.

- **Depreciation and Amortization** expenses increased $26 million primarily 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, and a higher depreciable base. The increase resulting from the lease modification was partially offset in Other Operation and Maintenance above.
- **Income Tax Expense** increased $2 million primarily due to an increase in pretax book income and a decrease in parent company loss benefit, partially offset by an increase in amortization of Excess ADIT and an increase in flow through tax benefits. The increase in amortization of Excess ADIT is partially offset in Retail Margins above.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
REVENUES		
Electric Generation, Transmission and Distribution	$ 612.0	$ 547.7
Sales to AEP Affiliates	2.0	0.8
Other Revenues – Affiliated	8.4	14.3
Other Revenues – Nonaffiliated	2.8	1.7
TOTAL REVENUES	625.2	564.5
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	50.0	36.3
Purchased Electricity for Resale	55.7	47.3
Purchased Electricity from AEP Affiliates	57.1	51.6
Other Operation	139.3	154.6
Maintenance	51.0	49.0
Depreciation and Amortization	134.9	109.2
Taxes Other Than Income Taxes	25.2	26.2
TOTAL EXPENSES	513.2	474.2
OPERATING INCOME	112.0	90.3
Other Income (Expense):		
Other Income	2.6	3.0
Non-Service Cost Components of Net Periodic Benefit Cost	6.3	4.1
Interest Expense	(30.3)	(27.3)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	90.6	70.1
Income Tax Expense (Benefit)	1.1	(0.7)
NET INCOME	$ 89.5	$ 70.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
Net Income	$ 89.5	$ 70.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 in 2022 and 2021, Respectively	0.4	0.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 in 2022 and 2021, Respectively	(0.1)	—
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.5
TOTAL COMPREHENSIVE INCOME	$ 89.8	$ 71.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2020	$ 56.6	$ 980.9	$ 1,718.7	$ (7.0)	$ 2,749.2
Common Stock Dividends			(25.0)		(25.0)
Net Income			70.8		70.8
Other Comprehensive Income				0.5	0.5
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2021	$ 56.6	$ 980.9	$ 1,764.5	$ (6.5)	$ 2,795.5
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2021	$ 56.6	$ 980.9	$ 1,748.5	$ (1.3)	$ 2,784.7
Common Stock Dividends			(25.0)		(25.0)
Net Income			89.5		89.5
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2022	$ 56.6	$ 980.9	$ 1,813.0	$ (1.0)	$ 2,849.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.3	$ 1.3
Advances to Affiliates	21.5	21.5
Accounts Receivable:		
Customers	42.4	40.6
Affiliated Companies	50.9	78.2
Miscellaneous	2.5	2.5
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	95.8	121.2
Fuel	54.8	56.8
Materials and Supplies	170.7	175.2
Risk Management Assets	1.5	3.3
Regulatory Asset for Under-Recovered Fuel Costs	4.6	6.4
Prepayments and Other Current Assets	47.2	53.7
TOTAL CURRENT ASSETS	399.4	439.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,535.2	5,531.8
Transmission	1,787.6	1,783.1
Distribution	2,847.7	2,800.1
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	802.3	792.9
Construction Work in Progress	331.1	302.8
Total Property, Plant and Equipment	11,303.9	11,210.7
Accumulated Depreciation, Depletion and Amortization	3,991.7	3,899.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,312.2	7,310.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	408.4	410.9
Spent Nuclear Fuel and Decommissioning Trusts	3,678.4	3,867.0
Operating Lease Assets	56.8	63.5
Deferred Charges and Other Noncurrent Assets	301.9	316.5
TOTAL OTHER NONCURRENT ASSETS	4,445.5	4,657.9
TOTAL ASSETS	$ 12,157.1	$ 12,408.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2022 and December 31, 2021
(dollars in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ 73.6	$ 93.3
Accounts Payable:		
General	153.9	174.4
Affiliated Companies	97.1	94.9
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2022 and December 31, 2021 Amounts Include $52 and $65, Respectively, Related to DCC Fuel)	304.0	67.0
Risk Management Liabilities	0.4	5.0
Customer Deposits	48.5	45.2
Accrued Taxes	117.3	106.5
Accrued Interest	24.7	37.0
Obligations Under Finance Leases	130.7	130.5
Obligations Under Operating Leases	13.4	15.5
Regulatory Liability for Over-Recovered Fuel Costs	5.8	1.5
Other Current Liabilities	87.0	123.2
TOTAL CURRENT LIABILITIES	1,056.4	894.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,867.7	3,128.0
Deferred Income Taxes	1,102.2	1,100.2
Regulatory Liabilities and Deferred Investment Tax Credits	2,218.2	2,447.9
Asset Retirement Obligations	1,966.6	1,946.2
Obligations Under Operating Leases	44.3	48.9
Deferred Credits and Other Noncurrent Liabilities	52.2	58.3
TOTAL NONCURRENT LIABILITIES	8,251.2	8,729.5
TOTAL LIABILITIES	9,307.6	9,623.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,813.0	1,748.5
Accumulated Other Comprehensive Income (Loss)	(1.0)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,849.5	2,784.7
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,157.1	$ 12,408.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
OPERATING ACTIVITIES		
Net Income	$ 89.5	$ 70.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	134.9	109.2
Rockport Plant, Unit 2 Operating Lease Amortization	—	16.6
Deferred Income Taxes	(11.5)	(12.1)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(6.5)	4.9
Allowance for Equity Funds Used During Construction	(2.9)	(3.5)
Mark-to-Market of Risk Management Contracts	(2.8)	2.7
Amortization of Nuclear Fuel	22.9	22.7
Deferred Fuel Over/Under-Recovery, Net	6.1	(9.3)
Change in Other Noncurrent Assets	(5.2)	2.6
Change in Other Noncurrent Liabilities	2.4	24.1
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	25.9	14.4
Fuel, Materials and Supplies	6.3	8.8
Accounts Payable	3.8	(14.8)
Accrued Taxes, Net	22.3	21.6
Other Current Assets	15.3	5.2
Other Current Liabilities	(53.6)	(45.8)
Net Cash Flows from Operating Activities	246.9	218.1
INVESTING ACTIVITIES		
Construction Expenditures	(129.9)	(120.2)
Purchases of Investment Securities	(507.7)	(336.9)
Sales of Investment Securities	493.5	320.0
Acquisitions of Nuclear Fuel	(31.1)	(55.9)
Other Investing Activities	0.3	3.2
Net Cash Flows Used for Investing Activities	(174.9)	(189.8)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(19.7)	21.6
Retirement of Long-term Debt – Nonaffiliated	(23.8)	(24.1)
Principal Payments for Finance Lease Obligations	(1.6)	(1.5)
Dividends Paid on Common Stock	(25.0)	(25.0)
Other Financing Activities	0.1	0.2
Net Cash Flows Used for Financing Activities	(70.0)	(28.8)
Net Increase (Decrease) in Cash and Cash Equivalents	2.0	(0.5)
Cash and Cash Equivalents at Beginning of Period	1.3	3.3
Cash and Cash Equivalents at End of Period	$ 3.3	$ 2.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 41.6	$ 42.0
Noncash Acquisitions Under Finance Leases	0.3	2.4
Construction Expenditures Included in Current Liabilities as of March 31,	60.7	50.5
Acquisition of Nuclear Fuel Included in Current Liabilities as of March 31,	—	6.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31,	
	2022	2021
	(in millions of KWhs)	
Retail:		
Residential	4,134	4,106
Commercial	3,851	3,502
Industrial	3,503	3,401
Miscellaneous	30	29
Total Retail (a)	11,518	11,038
Wholesale (b)	571	603
Total KWhs	12,089	11,641

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

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

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31,	
	2022	2021
	(in degree days)	
Actual – Heating (a)	1,864	1,777
Normal – Heating (b)	1,886	1,883
Actual – Cooling (c)	1	—
Normal – Cooling (b)	3	3

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

First Quarter of 2022 Compared to First Quarter of 2021

Ohio Power Company and Subsidiaries
Reconciliation of First Quarter of 2021 to First Quarter of 2022
Net Income
(in millions)

First Quarter of 2021	$	68.2
Changes in Gross Margin:		
Retail Margins		71.5
Margins from Off-system Sales		12.7
Transmission Revenues		3.0
Other Revenues		(8.3)
Total Change in Gross Margin		78.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(54.7)
Depreciation and Amortization		0.2
Taxes Other Than Income Taxes		(5.7)
Interest Income		(0.1)
Carrying Costs Income		(0.4)
Allowance for Equity Funds Used During Construction		0.3
Non-Service Cost Components of Net Periodic Benefit Cost		1.8
Interest Expense		2.4
Total Change in Expenses and Other		(56.2)
Income Tax Expense		(7.7)
First Quarter of 2022	$	83.2

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 $72 million primarily due to the following:
  - A $42 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $19 million increase in weather-normalized retail margins primarily in the commercial class partially offset by residential and industrial classes.
  - A $12 million increase related to various rider revenues. This increase was partially offset in Margins from Off-system Sales, Other Revenues and other expense items below.
- **Margins from Off-system Sales** increased $13 million primarily due to an increase in off-system sales at OVEC driven by higher market prices. This increase was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** increased $3 million primarily due to continued investment in transmission assets.
- **Other Revenues** decreased $8 million 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.

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

- **Other Operation and Maintenance** expenses increased $55 million primarily due to the following:
  - A $34 million increase in transmission expenses, primarily due to a $36 million increase in recoverable PJM expenses, partially offset by a $4 million decrease in transmission formula rate true-up activity. The recoverable PJM expenses were offset in Retail Margins above.
  - A $6 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.
  - A $5 million increase in factored customer accounts receivable expenses primarily due to bad debt expenses and a prior year adjustment to allowance for doubtful accounts.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to increased property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Income Tax Expense** increased $8 million primarily due to an increase in pretax book income and a favorable discrete adjustment recorded in 2021 that did not recur in 2022.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
REVENUES		
Electricity, Transmission and Distribution	$ 824.2	$ 716.7
Sales to AEP Affiliates	3.7	4.8
Other Revenues	2.1	2.4
TOTAL REVENUES	830.0	723.9
EXPENSES		
Purchased Electricity for Resale	226.3	175.3
Purchased Electricity from AEP Affiliates	6.3	30.1
Other Operation	237.6	184.6
Maintenance	40.4	38.7
Depreciation and Amortization	74.9	75.1
Taxes Other Than Income Taxes	127.0	121.3
TOTAL EXPENSES	712.5	625.1
OPERATING INCOME	117.5	98.8
Other Income (Expense):		
Interest Income	0.1	0.2
Carrying Costs Income	0.1	0.5
Allowance for Equity Funds Used During Construction	3.0	2.7
Non-Service Cost Components of Net Periodic Benefit Cost	5.5	3.7
Interest Expense	(29.2)	(31.6)
INCOME BEFORE INCOME TAX EXPENSE	97.0	74.3
Income Tax Expense	13.8	6.1
NET INCOME	$ 83.2	$ 68.2

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 321.2	$ 838.8	$ 1,532.7	$ 2,692.7
Common Stock Dividends			(21.9)	(21.9)
Net Income			68.2	68.2
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	$ 321.2	$ 838.8	$ 1,579.0	$ 2,739.0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 321.2	$ 838.8	$ 1,686.3	$ 2,846.3
Common Stock Dividends			(15.0)	(15.0)
Net Income			83.2	83.2
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2022	$ 321.2	$ 838.8	$ 1,754.5	$ 2,914.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 7.4	$ 3.0
Advances to Affiliates	—	42.0
Accounts Receivable:		
Customers	84.8	71.6
Affiliated Companies	77.6	71.8
Accrued Unbilled Revenues	14.7	1.3
Miscellaneous	3.0	5.9
Allowance for Uncollectible Accounts	(0.1)	(0.6)
Total Accounts Receivable	180.0	150.0
Materials and Supplies	80.0	74.1
Renewable Energy Credits	40.2	30.5
Prepayments and Other Current Assets	19.3	27.9
TOTAL CURRENT ASSETS	326.9	327.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,028.0	2,992.8
Distribution	6,141.3	6,070.6
Other Property, Plant and Equipment	996.9	992.9
Construction Work in Progress	385.2	365.0
Total Property, Plant and Equipment	10,551.4	10,421.3
Accumulated Depreciation and Amortization	2,483.9	2,458.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,067.5	7,963.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	279.4	293.0
Operating Lease Assets	79.2	81.2
Deferred Charges and Other Noncurrent Assets	505.1	601.1
TOTAL OTHER NONCURRENT ASSETS	863.7	975.3
TOTAL ASSETS	$ 9,258.1	$ 9,265.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2022 and December 31, 2021
(Unaudited)

	March 31, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 55.7	$ —
Accounts Payable:		
General	201.8	213.5
Affiliated Companies	117.6	125.4
Long-term Debt Due Within One Year – Nonaffiliated	0.1	0.1
Risk Management Liabilities	1.5	6.7
Customer Deposits	90.5	66.4
Accrued Taxes	544.2	702.4
Obligations Under Operating Leases	13.2	13.1
Other Current Liabilities	137.1	118.1
TOTAL CURRENT LIABILITIES	1,161.7	1,245.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,968.9	2,968.4
Long-term Risk Management Liabilities	67.0	85.8
Deferred Income Taxes	1,014.7	1,000.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,033.9	1,020.9
Obligations Under Operating Leases	66.6	68.6
Deferred Credits and Other Noncurrent Liabilities	30.8	29.2
TOTAL NONCURRENT LIABILITIES	5,181.9	5,173.8
TOTAL LIABILITIES	6,343.6	6,419.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,754.5	1,686.3
TOTAL COMMON SHAREHOLDER'S EQUITY	2,914.5	2,846.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 9,258.1	$ 9,265.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
OPERATING ACTIVITIES		
Net Income	$ 83.2	$ 68.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	74.9	75.1
Deferred Income Taxes	9.5	4.5
Allowance for Equity Funds Used During Construction	(3.0)	(2.7)
Mark-to-Market of Risk Management Contracts	(24.0)	(6.3)
Property Taxes	87.0	78.3
Change in Other Noncurrent Assets	(1.2)	(20.9)
Change in Other Noncurrent Liabilities	11.0	3.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(28.8)	(31.8)
Materials and Supplies	(5.0)	(3.7)
Accounts Payable	4.0	(6.4)
Customer Deposits	24.1	(0.7)
Accrued Taxes, Net	(158.3)	(144.7)
Other Current Assets	13.5	(0.2)
Other Current Liabilities	20.3	(1.3)
Net Cash Flows from Operating Activities	107.2	11.2
INVESTING ACTIVITIES		
Construction Expenditures	(188.7)	(178.2)
Change in Advances to Affiliates, Net	42.0	(0.5)
Other Investing Activities	4.2	2.6
Net Cash Flows Used for Investing Activities	(142.5)	(176.1)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	445.8
Change in Advances from Affiliates, Net	55.7	(259.2)
Principal Payments for Finance Lease Obligations	(1.2)	(1.2)
Dividends Paid on Common Stock	(15.0)	(21.9)
Other Financing Activities	0.2	0.1
Net Cash Flows from Financing Activities	39.7	163.6
Net Increase (Decrease) in Cash and Cash Equivalents	4.4	(1.3)
Cash and Cash Equivalents at Beginning of Period	3.0	7.4
Cash and Cash Equivalents at End of Period	$ 7.4	$ 6.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 19.5	$ 15.8
Noncash Acquisitions Under Finance Leases	0.6	0.4
Construction Expenditures Included in Current Liabilities as of March 31,	67.0	72.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2022	2021
	(in millions of KWhs)	
Retail:		
Residential	1,558	1,577
Commercial	1,120	1,050
Industrial	1,386	1,304
Miscellaneous	283	270
Total Retail	4,347	4,201
Wholesale	343	67
Total KWhs	4,690	4,268

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

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2022	2021
	(in degree days)	
Actual – Heating (a)	1,134	1,150
Normal – Heating (b)	1,040	1,033
Actual – Cooling (c)	11	7
Normal – Cooling (b)	17	17

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

First Quarter of 2022 Compared to First Quarter of 2021

Public Service Company of Oklahoma
Reconciliation of First Quarter of 2021 to First Quarter of 2022
Net Income (Loss)
(in millions)

First Quarter of 2021	$	(2.7)
Changes in Gross Margin:		
Retail Margins (a)		24.4
Transmission Revenues		0.1
Other Revenues		(0.8)
Total Change in Gross Margin		23.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(10.7)
Depreciation and Amortization		(2.8)
Taxes Other Than Income Taxes		(1.7)
Interest Income		1.6
Allowance for Equity Funds Used During Construction		0.7
Non-Service Cost Components of Net Periodic Benefit Cost		1.0
Interest Expense		(4.5)
Total Change in Expenses and Other		(16.4)
Income Tax Expense		1.2
First Quarter of 2022	$	5.8

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

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

- **Retail Margins** increased $24 million primarily due to the following:
  - A $27 million increase primarily due to a $15 million increase in rider revenues and a $12 million increase in base rate revenues. These increases were partially offset in other expense items below.

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

- **Other Operation and Maintenance** expenses increased $11 million primarily due to the following:
  - A $6 million increase in transmission expense primarily due to a $14 million increase in transmission investment offset by an $8 million decrease in recoverable SPP transmission expense. The recoverable SPP transmission expense was partially offset in Retail Margins above.
  - A $2 million increase in employee-related expenses.
- **Interest Expense** increased $5 million due to higher long-term debt balances.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
REVENUES		
Electric Generation, Transmission and Distribution	$ 386.4	$ 293.6
Sales to AEP Affiliates	0.6	1.0
Other Revenues	0.6	1.5
TOTAL REVENUES	387.6	296.1
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	188.7	120.9
Other Operation	88.8	79.1
Maintenance	25.4	24.4
Depreciation and Amortization	52.7	49.9
Taxes Other Than Income Taxes	14.2	12.5
TOTAL EXPENSES	369.8	286.8
OPERATING INCOME	17.8	9.3
Other Income (Expense):		
Interest Income	1.7	0.1
Allowance for Equity Funds Used During Construction	1.1	0.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.1	2.1
Interest Expense	(18.9)	(14.4)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT)	4.8	(2.5)
Income Tax Expense (Benefit)	(1.0)	0.2
NET INCOME (LOSS)	$ 5.8	$ (2.7)

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
Net Income (Loss)	$ 5.8	$ (2.7)
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $0 in 2022 and 2021, Respectively	—	(0.1)
TOTAL COMPREHENSIVE INCOME (LOSS)	$ 5.8	$ (2.8)

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 157.2	$ 414.0	$ 974.3	$ 0.1	$ 1,545.6
apital Contribution from Parent		425.0			425.0
et Loss			(2.7)		(2.7)
her Comprehensive Loss				(0.1)	(0.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	$ 157.2	$ 839.0	$ 971.6	$ —	$ 1,967.8
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 157.2	$ 1,039.0	$ 1,095.4	$ —	$ 2,291.6
et Income			5.8		5.8
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2022	$ 157.2	$ 1,039.0	$ 1,101.2	$ —	$ 2,297.4

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.9	$ 1.3
Accounts Receivable:		
Customers	40.7	41.5
Affiliated Companies	24.6	35.0
Miscellaneous	0.3	0.6
Total Accounts Receivable	65.6	77.1
Fuel	8.5	14.5
Materials and Supplies	63.1	56.2
Risk Management Assets	6.7	12.1
Accrued Tax Benefits	2.4	17.6
Regulatory Asset for Under-Recovered Fuel Costs	219.2	194.6
Prepayments and Other Current Assets	11.4	13.4
TOTAL CURRENT ASSETS	379.8	386.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,375.5	1,802.4
Transmission	1,115.4	1,107.7
Distribution	3,040.2	3,004.9
Other Property, Plant and Equipment	447.7	437.0
Construction Work in Progress	165.3	156.0
Total Property, Plant and Equipment	7,144.1	6,508.0
Accumulated Depreciation and Amortization	1,739.6	1,705.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,404.5	4,802.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,042.0	1,037.4
Employee Benefits and Pension Assets	96.0	95.2
Operating Lease Assets	107.9	68.9
Deferred Charges and Other Noncurrent Assets	47.1	7.9
TOTAL OTHER NONCURRENT ASSETS	1,293.0	1,209.4
TOTAL ASSETS	$ 7,077.3	$ 6,399.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2022 and December 31, 2021
(Unaudited)

	March 31, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 211.8	$ 72.3
Accounts Payable:		
General	127.7	157.4
Affiliated Companies	42.3	51.0
Long-term Debt Due Within One Year – Nonaffiliated	625.5	125.5
Risk Management Liabilities	0.1	3.7
Customer Deposits	58.2	56.2
Accrued Taxes	57.0	27.0
Obligations Under Operating Leases	7.7	6.9
Other Current Liabilities	59.7	62.7
TOTAL CURRENT LIABILITIES	1,190.0	562.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,788.1	1,788.0
Deferred Income Taxes	779.0	782.3
Regulatory Liabilities and Deferred Investment Tax Credits	831.3	835.3
Asset Retirement Obligations	71.1	57.5
Obligations Under Operating Leases	100.9	62.2
Deferred Credits and Other Noncurrent Liabilities	19.5	19.4
TOTAL NONCURRENT LIABILITIES	3,589.9	3,544.7
TOTAL LIABILITIES	4,779.9	4,107.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	1,039.0	1,039.0
Retained Earnings	1,101.2	1,095.4
TOTAL COMMON SHAREHOLDER'S EQUITY	2,297.4	2,291.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,077.3	$ 6,399.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
OPERATING ACTIVITIES		
Net Income (Loss)	$ 5.8	$ (2.7)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	52.7	49.9
Deferred Income Taxes	(17.4)	(0.8)
Allowance for Equity Funds Used During Construction	(1.1)	(0.4)
Mark-to-Market of Risk Management Contracts	1.8	4.8
Property Taxes	(37.8)	(32.8)
Deferred Fuel Over/Under-Recovery, Net	(26.4)	(703.5)
Change in Other Noncurrent Assets	(3.9)	(7.3)
Change in Other Noncurrent Liabilities	6.2	1.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	11.5	(11.2)
Fuel, Materials and Supplies	—	4.5
Accounts Payable	(20.8)	15.2
Accrued Taxes, Net	45.2	22.4
Other Current Assets	1.9	(0.3)
Other Current Liabilities	(1.8)	(24.7)
Net Cash Flows from (Used for) Operating Activities	15.9	(685.4)
INVESTING ACTIVITIES		
Construction Expenditures	(104.1)	(79.9)
Acquisition of the North Central Wind Energy Facilities	(549.3)	—
Other Investing Activities	0.4	0.5
Net Cash Flows Used for Investing Activities	(653.0)	(79.4)
FINANCING ACTIVITIES		
Capital Contributions from Parent	—	425.0
Issuance of Long-term Debt – Nonaffiliated	500.0	500.0
Change in Advances from Affiliates, Net	139.5	90.3
Retirement of Long-term Debt – Nonaffiliated	(0.1)	(250.1)
Principal Payments for Finance Lease Obligations	(0.8)	(0.9)
Other Financing Activities	0.1	0.3
Net Cash Flows from Financing Activities	638.7	764.6
Net Increase (Decrease) in Cash and Cash Equivalents	1.6	(0.2)
Cash and Cash Equivalents at Beginning of Period	1.3	2.6
Cash and Cash Equivalents at End of Period	$ 2.9	$ 2.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 21.3	$ 16.9
Noncash Acquisitions Under Finance Leases	0.3	1.0
Construction Expenditures Included in Current Liabilities as of March 31,	37.1	22.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2022	2021
	(in millions of KWhs)	
Retail:		
Residential	1,636	1,700
Commercial	1,266	1,209
Industrial	1,115	971
Miscellaneous	18	18
Total Retail	4,035	3,898
Wholesale	1,759	1,541
Total KWhs	5,794	5,439

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

Summary of Heating and Cooling Degree Days

	Three Months Ended March 31, 2022	2021
	(in degree days)	
Actual – Heating (a)	694	763
Normal – Heating (b)	700	697
Actual – Cooling (c)	30	45
Normal – Cooling (b)	40	40

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

First Quarter of 2022 Compared to First Quarter of 2021

Reconciliation of First Quarter of 2021 to First Quarter of 2022
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

First Quarter of 2021	$	62.4
Changes in Gross Margin:		
Retail Margins (a)		(12.4)
Margins from Off-system Sales		(13.1)
Transmission Revenues		6.0
Other Revenues		(0.2)
Total Change in Gross Margin		(19.7)
Changes in Expenses and Other:		
Other Operation and Maintenance		2.7
Depreciation and Amortization		(8.2)
Taxes Other Than Income Taxes		0.2
Interest Income		2.6
Allowance for Equity Funds Used During Construction		(0.5)
Non-Service Cost Components of Net Periodic Benefit Cost		1.0
Interest Expense		(3.8)
Total Change in Expenses and Other		(6.0)
Income Tax Expense		7.8
Equity Earnings of Unconsolidated Subsidiary		(0.4)
First Quarter of 2022	$	44.1

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

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

- **Retail Margins** decreased $12 million primarily due to the following:
  - A $21 million decrease in municipal and cooperative revenues primarily due to the February 2021 severe winter weather event.
  - A $6 million decrease in recoverable fuel costs primarily due to timing of recovery.
  - A $4 million decrease in weather-related usage primarily due to a 9% decrease in heating degree days.

  These decreases were partially offset by:
  - A $10 million increase primarily due to a base rate revenue increase in Texas and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $9 million increase in weather-normalized margins.
- **Margins from Off-system Sales** decreased $13 million primarily due to Turk Plant merchant sales as a result of the February 2021 severe winter weather event.
- **Transmission Revenues** increased $6 million primarily due to transmission investment.

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

- **Other Operation and Maintenance** expenses decreased $3 million primarily due to the following:
  - A $5 million decrease in generation plant maintenance expenses.
  - A $3 million decrease in distribution expense primarily driven by prior year storm expenses.

  These decreases were partially offset by:

- A $4 million increase in transmission expense primarily due to an increase in vegetation management expenses.

- **Depreciation and Amortization** expenses increased $8 million primarily due to the implementation of new rates in Texas and a higher depreciable base.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $8 million primarily due to an increase in PTC and a decrease in pretax book income, partially offset by a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was partially offset in Retail Margins above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
REVENUES		
Electric Generation, Transmission and Distribution	$ 484.2	$ 607.7
Sales to AEP Affiliates	10.0	7.8
Other Revenues	0.6	0.6
TOTAL REVENUES	494.8	616.1
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	198.2	299.8
Other Operation	91.5	90.3
Maintenance	30.1	34.0
Depreciation and Amortization	77.8	69.6
Taxes Other Than Income Taxes	29.8	30.0
TOTAL EXPENSES	427.4	523.7
OPERATING INCOME	67.4	92.4
Other Income (Expense):		
Interest Income	3.6	1.0
Allowance for Equity Funds Used During Construction	1.6	2.1
Non-Service Cost Components of Net Periodic Benefit Cost	3.1	2.1
Interest Expense	(33.1)	(29.3)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	42.6	68.3
Income Tax Expense (Benefit)	(2.2)	5.6
Equity Earnings of Unconsolidated Subsidiary	0.3	0.7
NET INCOME	45.1	63.4
Net Income Attributable to Noncontrolling Interest	1.0	1.0
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 44.1	$ 62.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2022	**2021**
Net Income	$ 45.1	$ 63.4
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $0.1 in 2022 and 2021, Respectively	0.1	0.4
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) in 2022 and 2021, Respectively	(0.4)	(0.4)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.3)	—
TOTAL COMPREHENSIVE INCOME	44.8	63.4
Total Comprehensive Income Attributable to Noncontrolling Interest	1.0	1.0
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 43.8	$ 62.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2020	$ 0.1	$ 812.2	$ 1,811.9	$ 1.9	$ 1.6	$ 2,627.7
Capital Contribution from Parent		100.0				100.0
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			62.4		1.0	63.4
TOTAL EQUITY – MARCH 31, 2021	$ 0.1	$ 912.2	$ 1,874.3	$ 1.9	$ 1.6	$ 2,790.1
TOTAL EQUITY – DECEMBER 31, 2021	$ 0.1	$ 1,092.2	$ 2,050.9	$ 6.7	$ (0.1)	$ 3,149.8
Capital Contribution from Parent		350.0				350.0
Common Stock Dividends – Nonaffiliated					(0.8)	(0.8)
Net Income			44.1		1.0	45.1
Other Comprehensive Loss				(0.3)		(0.3)
TOTAL EQUITY – MARCH 31, 2022	$ 0.1	$ 1,442.2	$ 2,095.0	$ 6.4	$ 0.1	$ 3,543.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2022 and December 31, 2021
(in millions)
(Unaudited)

	March 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents (March 31, 2022 and December 31, 2021 Amounts Include $54.8 and $49.9, Respectively, Related to Sabine)	$ 58.1	$ 51.2
Advances to Affiliates	2.1	155.9
Accounts Receivable:		
Customers	31.5	35.8
Affiliated Companies	28.4	38.3
Miscellaneous	18.9	12.3
Total Accounts Receivable	78.8	86.4
Fuel (March 31, 2022 and December 31, 2021 Amounts Include $19.5 and $13.1, Respectively, Related to Sabine)	81.5	82.2
Materials and Supplies (March 31, 2022 and December 31, 2021 Amounts Include $11 and $12, Respectively, Related to Sabine)	84.3	81.9
Risk Management Assets	15.8	9.8
Accrued Tax Benefits	13.2	17.8
Regulatory Asset for Under-Recovered Fuel Costs	209.8	143.9
Prepayments and Other Current Assets	34.2	39.4
TOTAL CURRENT ASSETS	577.8	668.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,434.3	4,734.5
Transmission	2,357.2	2,316.9
Distribution	2,548.3	2,514.3
Other Property, Plant and Equipment (March 31, 2022 and December 31, 2021 Amounts Include $219.9 and $219.9, Respectively, Related to Sabine)	781.5	764.0
Construction Work in Progress	213.8	240.7
Total Property, Plant and Equipment	11,335.1	10,570.4
Accumulated Depreciation and Amortization (March 31, 2022 and December 31, 2021 Amounts Include $179.3 and $168.1, Respectively, Related to Sabine)	3,247.8	3,170.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,087.3	7,400.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	962.3	1,005.3
Deferred Charges and Other Noncurrent Assets	338.4	251.8
TOTAL OTHER NONCURRENT ASSETS	1,300.7	1,257.1
TOTAL ASSETS	$ 9,965.8	$ 9,325.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2022 and December 31, 2021
(Unaudited)

	March 31, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 202.9	$ —
Accounts Payable:		
General	125.1	163.6
Affiliated Companies	42.7	61.4
Long-term Debt Due Within One Year – Nonaffiliated	6.2	6.2
Risk Management Liabilities	—	2.1
Customer Deposits	64.1	62.4
Accrued Taxes	115.4	44.3
Accrued Interest	29.4	36.0
Obligations Under Operating Leases	8.5	8.1
Other Current Liabilities	108.0	154.6
TOTAL CURRENT LIABILITIES	702.3	538.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,387.9	3,389.0
Deferred Income Taxes	1,084.5	1,087.6
Regulatory Liabilities and Deferred Investment Tax Credits	822.1	806.9
Asset Retirement Obligations	219.8	192.7
Employee Benefits and Pension Obligations	21.0	20.3
Obligations Under Operating Leases	124.2	77.7
Deferred Credits and Other Noncurrent Liabilities	60.2	63.0
TOTAL NONCURRENT LIABILITIES	5,719.7	5,637.2
TOTAL LIABILITIES	6,422.0	6,175.9
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	0.1	0.1
Paid-in Capital	1,442.2	1,092.2
Retained Earnings	2,095.0	2,050.9
Accumulated Other Comprehensive Income (Loss)	6.4	6.7
TOTAL COMMON SHAREHOLDER'S EQUITY	3,543.7	3,149.9
Noncontrolling Interest	0.1	(0.1)
TOTAL EQUITY	3,543.8	3,149.8
TOTAL LIABILITIES AND EQUITY	$ 9,965.8	$ 9,325.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended March 31, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 45.1	$ 63.4
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	77.8	69.6
Deferred Income Taxes	(9.5)	8.6
Allowance for Equity Funds Used During Construction	(1.6)	(2.1)
Mark-to-Market of Risk Management Contracts	(7.0)	1.1
Property Taxes	(64.5)	(61.6)
Deferred Fuel Over/Under-Recovery, Net	9.2	(461.1)
Change in Regulatory Assets	(3.5)	(89.1)
Change in Other Noncurrent Assets	33.4	6.1
Change in Other Noncurrent Liabilities	16.7	16.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	7.6	(105.8)
Fuel, Materials and Supplies	(0.6)	0.4
Accounts Payable	(35.1)	95.1
Accrued Taxes, Net	75.7	73.9
Other Current Assets	3.8	8.2
Other Current Liabilities	(56.7)	(51.0)
Net Cash Flows from (Used for) Operating Activities	90.8	(427.7)
INVESTING ACTIVITIES		
Construction Expenditures	(129.5)	(91.4)
Change in Advances to Affiliates, Net	153.8	—
Acquisition of the North Central Wind Energy Facilities	(658.0)	—
Other Investing Activities	1.9	0.1
Net Cash Flows Used for Investing Activities	(631.8)	(91.3)
FINANCING ACTIVITIES		
Capital Contribution from Parent	350.0	100.0
Issuance of Long-term Debt – Nonaffiliated	—	496.8
Change in Short-term Debt – Nonaffiliated	—	(30.0)
Change in Advances from Affiliates, Net	202.9	(37.7)
Retirement of Long-term Debt – Nonaffiliated	(1.6)	(1.6)
Principal Payments for Finance Lease Obligations	(2.7)	(2.6)
Dividends Paid on Common Stock – Nonaffiliated	(0.8)	(1.0)
Other Financing Activities	0.1	0.1
Net Cash Flows from Financing Activities	547.9	524.0
Net Increase in Cash and Cash Equivalents	6.9	5.0
Cash and Cash Equivalents at Beginning of Period	51.2	13.2
Cash and Cash Equivalents at End of Period	$ 58.1	$ 18.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 37.7	$ 39.7
Noncash Acquisitions Under Finance Leases	1.0	1.5
Construction Expenditures Included in Current Liabilities as of March 31,	47.8	40.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three months ended March 31, 2022 is not necessarily indicative of results that may be expected for the year ending December 31, 2022. The condensed financial statements are unaudited and should be read in conjunction with the audited 2021 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 24, 2022.

AEP System Tax Allocation

The Registrant Subsidiaries join in the filing of a consolidated 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 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 is immaterial to the Registrant Subsidiaries' financial statements.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Three Months Ended March 31,			
	2022		2021	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 714.7		$ 575.0	
Weighted-Average Number of Basic AEP Common Shares Outstanding	506.1	$ 1.41	497.1	$ 1.16
Weighted-Average Dilutive Effect of Stock-Based Awards	1.6	—	1.1	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	507.7	$ 1.41	498.2	$ 1.15

Equity Units are potentially dilutive securities and were excluded from the calculation of diluted EPS for the three months ended March 31, 2022 and 2021, as the dilutive stock price threshold was not met. See Note 12 - Financing Activities for more information related to Equity Units.

There were no antidilutive shares outstanding as of March 31, 2022 and 2021, respectively.

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	March 31, 2022		
	AEP	AEP Texas	APCo
		(in millions)	
Cash and Cash Equivalents	$ 675.6	$ 0.1	$ 6.0
Restricted Cash	49.9	39.9	10.0
Total Cash, Cash Equivalents and Restricted Cash	$ 725.5	$ 40.0	$ 16.0

	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

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. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional information.

AEP

Three Months Ended March 31, 2022	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2021	$ 163.7	$ (21.3)	$ 42.4	$ 184.8
Change in Fair Value Recognized in AOCI	278.2	6.8 (a)	—	285.0
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (b)	(47.9)	—	—	(47.9)
Interest Expense (b)	—	1.1	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	(4.9)	(4.9)
Amortization of Actuarial (Gains) Losses	—	—	2.1	2.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(48.0)	1.1	(2.8)	(49.7)
Income Tax (Expense) Benefit	(10.1)	0.2	(0.6)	(10.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(37.9)	0.9	(2.2)	(39.2)
Net Current Period Other Comprehensive Income (Loss)	240.3	7.7	(2.2)	245.8
Balance in AOCI as of March 31, 2022	$ 404.0	$ (13.6)	$ 40.2	$ 430.6

Three Months Ended March 31, 2021	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2020	$ (60.6)	$ (47.5)	$ 23.0	$ (85.1)
Change in Fair Value Recognized in AOCI	177.3	13.1 (a)	—	190.4
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	0.8	—	—	0.8
Purchased Electricity for Resale (b)	(172.0)	—	—	(172.0)
Interest Expense (b)	—	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains) Losses	—	—	2.3	2.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(171.2)	1.5	(2.5)	(172.2)
Income Tax (Expense) Benefit	(36.0)	0.4	(0.5)	(36.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(135.2)	1.1	(2.0)	(136.1)
Net Current Period Other Comprehensive Income (Loss)	42.1	14.2	(2.0)	54.3
Balance in AOCI as of March 31, 2021	$ (18.5)	$ (33.3)	$ 21.0	$ (30.8)

AEP Texas

Three Months Ended March 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ (1.3)	$ (5.2)	$ (6.5)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of March 31, 2022	$ (1.0)	$ (5.2)	$ (6.2)

Three Months Ended March 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (2.3)	$ (6.6)	$ (8.9)
Change in Fair Value Recognized in AOCI	0.1	—	0.1
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.3	—	0.3
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.2	—	0.2
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of March 31, 2021	$ (2.0)	$ (6.6)	$ (8.6)

APCo

Three Months Ended March 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ 7.5	$ 16.9	$ 24.4
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.3)	—	(0.3)
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)	(1.4)	(1.7)
Income Tax (Expense) Benefit	(0.1)	(0.3)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.2)	(1.1)	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(0.2)	(1.1)	(1.3)
Balance in AOCI as of March 31, 2022	$ 7.3	$ 15.8	$ 23.1

Three Months Ended March 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (0.8)	$ 8.0	$ 7.2
Change in Fair Value Recognized in AOCI	9.3	—	9.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.4)	—	(0.4)
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.4)	(1.4)	(1.8)
Income Tax (Expense) Benefit	(0.1)	(0.3)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.3)	(1.1)	(1.4)
Net Current Period Other Comprehensive Income (Loss)	9.0	(1.1)	7.9
Balance in AOCI as of March 31, 2021	$ 8.2	$ 6.9	$ 15.1

I&M

Three Months Ended March 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ (6.7)	$ 5.4	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.1)	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.1)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.1)	0.3
Balance in AOCI as of March 31, 2022	$ (6.3)	$ 5.3	$ (1.0)

Three Months Ended March 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (8.3)	$ 1.3	$ (7.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.6	—	0.6
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.5	—	0.5
Net Current Period Other Comprehensive Income (Loss)	0.5	—	0.5
Balance in AOCI as of March 31, 2021	$ (7.8)	$ 1.3	$ (6.5)

PSO

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

Three Months Ended March 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	—
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 March 31, 2021	$ —

SWEPCo

Three Months Ended March 31, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ 1.2	$ 5.5	$ 6.7
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.1	—	0.1
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.1	(0.5)	(0.4)
Income Tax (Expense) Benefit	—	(0.1)	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.1	(0.4)	(0.3)
Net Current Period Other Comprehensive Income (Loss)	0.1	(0.4)	(0.3)
Balance in AOCI as of March 31, 2022	$ 1.3	$ 5.1	$ 6.4

Three Months Ended March 31, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (0.3)	$ 2.2	$ 1.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.5)	—
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.4)	—
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.4)	—
Balance in AOCI as of March 31, 2021	$ 0.1	$ 1.8	$ 1.9

(a) The change in fair value includes $4 million and $4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the three months ended March 31, 2022 and 2021, respectively.
(b) Amounts reclassified to the referenced line item on the statements of income.

4. RATE MATTERS

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

As discussed in the 2021 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2021 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2022 and updates the 2021 Annual Report.

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

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

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

Regulated Generating Units that have been Retired

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 below for additional information. As part of the 2019 Arkansas Base Rate Case, SWEPCo received approval from the APSC to recover the Arkansas jurisdictional share of Welsh Plant, Unit 2. In December 2020, SWEPCo filed a request with the LPSC to recover the Louisiana jurisdictional share of Welsh Plant, Unit 2. See "2020 Louisiana Base Rate Case" section below for additiona information. As of March 31, 2022, SWEPCo had a regulatory asset for plant retirement costs pending approval recorded on its balance sheet of $35 million related to the Louisiana jurisdictional share of Welsh Plant, Unit 2.

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, but denied SWEPCo the ability to earn a return on this investment resulting ir a disallowance of $12 million in 2021. SWEPCo has also requested recovery of the Dolet Hills Power Station in the Arkansas and Louisiana jurisdictions through base rate cases. See "2020 Texas Base Rate Case", "2020 Louisiana Base Rate Case" and "2021 Arkansas Base Rate Case" sections below for additional information. The Dolet Hills Power Station is currently being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Arkansas and Texas jurisdictions. As of March 31, 2022, SWEPCo had a regulatory asset for the Dolet Hills Power Statior pending approval recorded on its balance sheet of $72 million related to the Arkansas and Louisiana jurisdictional shares.

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 Power Plant in 2023 and that it will cease using coal at the Welsh Plant in 2028. As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of March 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	$ 159.1	$ 132.5	$ 20.1	(b)	2026	(c)	$ 14.9
Pirkey Power Plant	99.6	107.7	39.3		2023	(d)	13.4
Welsh Plant, Units 1 and 3	467.2	55.7	58.6	(e)	2028	(f)	37.3

(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 Power Plant is currently being recovered through 2025 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 December 2021, the Dolet Hills Power Station was retired. The Dolet Hills Power Station non-fuel costs are recoverable by SWEPCo through base rates and through a rate rider in the Texas jurisdiction. As of March 31, 2022, SWEPCo's share of the net investment in the Dolet Hills Power Station was $108 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. As of March 31, 2022, SWEPCo had a net under-recovered fuel balance of $84 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Dolet Hills Power Station. Additional reclamation and other land-related costs incurred by DHLC and Oxbow will be billed to SWEPCo and included in existing fuel clauses.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $30 million of additional costs with a recovery period to be determined at a later date. In November 2021, the LPSC issued a directive which deferred the issues regarding modification of the level and timing of recovery of the Dolet Hills Power Station from SWEPCo's pending rate case to a separate existing docket. In addition, the recovery of the deferred fuel costs are planned to be addressed.

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

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

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

In 2020, management announced plans to retire the Pirkey Power Plant in 2023. The Pirkey Power Plant non-fuel costs are recoverable by SWEPCo through base rates and fuel costs are recovered through active fuel clauses. As of March 31, 2022, SWEPCo's share of the net investment in the Pirkey Power Plant was $207 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Power Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $87 million as of March 31, 2022. As of March 31, 2022, SWEPCo had a net under-recovered fuel balance of $84 million, excluding impacts of the February 2021 severe winter weather event, which includes fuel consumed at the Pirkey Power Plant. Additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in 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 Pending Final Regulatory Approval (Applies to all Registrants except AEPTCo)

	AEP	
Noncurrent Regulatory Assets	**March 31, 2022**	**December 31, 2021**
	(in millions)	
Regulatory Assets Currently Earning a Return		
Unrecovered Winter Storm Fuel Costs (a)	$ 236.8	$ 430.2
Pirkey Power Plant Accelerated Depreciation	107.7	87.0
Dolet Hills Power Station Accelerated Depreciation	72.2	72.3
Welsh Plant, Units 1 and 3 Accelerated Depreciation	55.7	45.9
Plant Retirement Costs – Unrecovered Plant, Louisiana	35.2	35.2
Dolet Hills Power Station Fuel Costs - Louisiana	31.3	30.9
Other Regulatory Assets Pending Final Regulatory Approval	10.5	9.2
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	279.6	256.9
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
COVID-19	11.9	11.2
Other Regulatory Assets Pending Final Regulatory Approval	46.1	43.9
Total Regulatory Assets Pending Final Regulatory Approval	$ 912.9	$ 1,048.6

(a) Includes $63 million and $63 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of March 31, 2022 and December 31, 2021, respectively.

	AEP Texas	
Noncurrent Regulatory Assets	**March 31, 2022**	**December 31, 2021**
	(in millions)	
Regulatory Assets Currently Earning a Return		
Mobile Generation Lease Payments	$ 1.3	$ —
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	23.6	22.4
Vegetation Management Program	5.2	5.2
Texas Retail Electric Provider Bad Debt Expense	4.1	4.1
COVID-19	3.6	2.1
Other Regulatory Assets Pending Final Regulatory Approval	8.0	7.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 45.8	$ 41.2

	APCo	
Noncurrent Regulatory Assets	**March 31, 2022**	**December 31, 2021**
	(in millions)	
Regulatory Assets Currently Earning a Return		
COVID-19 – Virginia	$ 6.8	$ 6.8
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	75.2	68.8
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
Other Regulatory Assets Pending Final Regulatory Approval	5.0	3.6
Total Regulatory Assets Pending Final Regulatory Approval	$ 112.9	$ 105.1

Noncurrent Regulatory Assets	I&M March 31, 2022	I&M December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 0.1
Regulatory Assets Currently Not Earning a Return		
COVID-19	0.2	1.7
Other Regulatory Assets Pending Final Regulatory Approval	0.8	1.9
Total Regulatory Assets Pending Final Regulatory Approval	$ 1.1	$ 3.7

Noncurrent Regulatory Assets	OPCo March 31, 2022	OPCo December 31, 2021
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 9.1	$ 3.8
Total Regulatory Assets Pending Final Regulatory Approval	$ 9.1	$ 3.8

Noncurrent Regulatory Assets	PSO March 31, 2022	PSO December 31, 2021
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 20.5	$ 13.9
COVID-19	—	0.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 20.5	$ 14.2

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Noncurrent Regulatory Assets	SWEPCo March 31, 2022	SWEPCo December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
Unrecovered Winter Storm Fuel Costs (a)	$ 236.8	$ 430.2
Pirkey Power Plant Accelerated Depreciation	107.7	87.0
Dolet Hills Power Station Accelerated Depreciation	72.2	72.3
Welsh Plant, Units 1 and 3 Accelerated Depreciation	55.7	45.9
Plant Retirement Costs – Unrecovered Plant, Louisiana	35.2	35.2
Dolet Hills Power Station Fuel Costs- Louisiana	31.3	30.9
Other Regulatory Assets Pending Final Regulatory Approval	2.3	2.4
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	151.2	148.0
Asset Retirement Obligation - Louisiana	10.6	10.3
Other Regulatory Assets Pending Final Regulatory Approval	20.0	18.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 723.0	$ 880.6

(a) Includes $63 million and $63 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of March 31, 2022 and December 31, 2021, respectively.

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

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

AEP Texas Interim Transmission and Distribution Rates

Through March 31, 2022, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is approximately $368 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 prospective9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top).

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

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

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

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

In March 2021, the Virginia SCC issued an order confirming certain decisions from the November 2020 order and rejecting the various requests for reconsideration from APCo and an intervenor. In March 2021, APCo filed a notice of appeal of the reconsideration order with the Virginia Supreme Court. In September 2021, APCo submitted its brief before the Virginia Supreme Court.The brief was in alignment with the previous items of appeal filed by APCo in March 2021. In October 2021, the Virginia SCC and additional intervenors filed briefs with the Virginia Supreme Court disagreeing with the items appealed by APCo in the Triennial Review decision. Additionally, the Virginia SCC and APCo filed briefs disagreeing with the items appealed by an intervenor in a separate appeal of the same decision. In March 2022, oral arguments were held at the Virginia Supreme Court and APCo is currently awaiting the Virginia Supreme Court's decision.

APCo ultimately seeks an increase in base rates through its appeal to the Virginia Supreme Court.Among other issues, this appeal includes APCo's request for proper treatment of the closed coal-fired plant assets in APCo's 2017-2019 triennial period, reducing APCo's earnings below the bottom of its authorized ROE band. If APCo's appeal regarding treatment of the closed coal plants is granted by the Virginia Supreme Court, it could initially reduce future net income and impact financial condition as a consequence of expensing the closed coal-fired plant regulatory asset established as a result of the Virginia SCC's decision in the 2017-2019 Triennial Review. A Virginia Supreme Court decision in favor of APCo's original expensing of the closed coal-fired plant asset balances would likely result in a remand to the Virginia SCC. Upon a subsequent Virginia SCC order, the initial negative impact for the write-off of the closed coal-fired plant asset balances could potentially be offset by an increase in base rates for earning below APCo's 2017-2019 authorized ROE band.

CCR/ELG Compliance Plan Filings

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

In August 2021, the Virginia SCC issued an order approving APCo's request to construct CCR-related investments at the Amos and Mountaineer Plants and approved recovery of CCR-related other operation and maintenance expenses and investments through an active rider. The order denied APCo's request to construct the ELG investments and denied recovery of previously incurred ELG costsIn March 2022, APCo refiled for approval of the ELG investments and previously incurred ELG costs.A hearing is scheduled to take place in September 2022 and an order is anticipated in the fourth quarter of 2022.

Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approve recovery of the West Virginia jurisdictional share of these costs through an active rider. In October 2021, due to the Virginia SCC previously rejecting the ELG investments, the WVPSC issued an order directing APCo to proceed with CCR/ELG compliance plans that would allow the plants t continue operating beyond 2028. The October order further states that APCo will not share capacity and energy from the plants with customers from Virginia if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plants to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that APCo will be given the opportunity to recover, from West Virginia customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plants beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred.In October and November 2021, intervenors filed petitions for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

APCo expects total Amos and Mountaineer Plant ELG investment, excluding AFUDC, to be approximately $197 million. As of March 31, 2022, APCo’s Virginia jurisdictional share of the net book value, before cost of removal including CWIP and inventory, of the Amos and Mountaineer Plants was approximately $1.5 billion and APCo’s Virginia jurisdictional share of its ELG investment balance in CWIP for these plants was $41 million.

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

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 modifying the original $48 million reduction to a $17 million reduction related to 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 projections related to 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. It is anticipated that the WVPSC will issue an order on the reopened 2021 ENEC filing in the second quarter of 2022.

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. As of March 31, 2022, the Companies’ cumulative ENEC under-recovery was $243 million. If any deferred ENEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT’s revenues are based on 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 March 31, 2022, AEP’s share of ETT’s cumulative revenues that are subject to review is approximately $1.4 billion. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. ETT is required to file for a comprehensive rate review no later than February 1, 2023, during which the $1.4 billion of cumulative revenues above will be subject to review.

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

Michigan Power Supply Cost Recovery (PSCR) Reconciliation

In April 2022, an Administrative Law Judge (ALJ) issued a Proposal for Decision (PFD) for I&M's PSCR reconciliation for the 12-month perio 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. Management disagrees with the ALJ's recommended cost disallowances and intends to file exceptions to the PFD. I&M anticipates that the MPSC will issue a final decision in the second half of 2022. Management is unable to predict the impact, if any, that the MPSC's final decision may have on future results of operations, financial condition and cash flows.

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

CCR/ELG Compliance Plan Filings

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

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

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval of a proposed Mitchell Plant Operations ai Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo would replace KPCo as th operator of the Mitchell Plant. In February 2022, AEP filed a motion to withdraw its filing with the FERC, noting that AEP intends to re-file its request after the KPSC and WVPSC have reviewed the agreements. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

As of March 31, 2022, KPCo's share of the Mitchell Plant's ELG investment balance in CWIP was $4 million. As of March 31, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $585 million.

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

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

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. Management disagrees with these claims and is unable to predict the impact, if any, these disputes may have on future results of operations, financial condition and cash flows. See "OVEC" section of Note 17 in the 2021 Annual Report for additional information on AEP and OPCo's investment in OVEC.

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

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. For the time period of February 9, 2021, to February 20, 2021, PSO's natural gas expenses and purchases of electricity still to be recovered from customers are $681 million as of March 31, 2022.

In April 2021, the OCC approved a waiver for PSO allowing the deferral of the extraordinary fuel and purchases of electricity, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. In January 2022, PSO, OCC staff and certain intervenors filed a joint stipulation and settlement agreement with the OCC to approve PSO's securitization of the extraordinary fuel and purchases of electricity. The agreement includes a determination that all of PSO's extraordinary fuel and purchases of electricity were prudent and reasonable and a 0.75% carrying charge, subject to true-up based on actual financing costs. In February 2022, the OCC approved the joint stipulation and settlement agreement in its financing order. The issuance of the securitization bonds must be approved by the Supreme Court of Oklahoma. A ruling by the Supreme Court is expected in the second quarter of 2022. PSO expects to complete the securitization process in 2022, subject to market conditions.

<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 and submitted a Petition for Review with the Texas Supreme Court in November 2021. The Texas Supreme Court has requested responses to the Petition for Review, which are due at the end of April 2022.

If SWEPCo is ultimately unable to recover capitalized Turk Plant costs, including 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 $180 million related to revenues collected from February 2013 through March 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. 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. The proposed net annual increase: (a) includes $5 million related to vegetation management to maintain and improve the reliability of SWEPCo's Texas jurisdictional distribution system, (b) requests a $10 million annual depreciation increase and (c) seeks $2 million annually to establish a storm catastrophe reserve. In addition, SWEPCo also requested recovery of the Texas jurisdictional share of the Dolet Hills Power Station of $45 million which was retired in December 2021. SWEPCo subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to $100 million which would result in an $85 million net annual base rate increase after moving the proposed riders to rate base.

In 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 that would recover the Dolet Hills Power Station as if it were in rate base until its retirement at the end of 2021 and starting in 2022 the remaining net book value would be recovered as a regulatory asset through 2046. 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.

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 subsequently revised the requested annual increase to $114 million to reflect removing hurricane storm restoration costs from the base case filing. The hurricane costs have been requested in a separate storm filing. See "2021 Louisiana Storm Cost Filing" below for more information. The base case filing would extend the formula rate plan for five years and includes modifications to the formula rate plan to allow for forward-looking transmission costs, reflects the impact of net operating losses associated with the acceleration of certain tax benefits and incorporates future federal corporate income tax changes. The proposed net annual increase requests a $32 million annual depreciation increase to recover Louisiana's share of the Dolet Hills Power Station, Pirkey Power Plant and Welsh Plant, all of which are expected to be retired early.

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

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

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

2021 Arkansas Base Rate Case

In July 2021, SWEPCo filed a request with the APSC for an $85 million annual increase in Arkansas base rates based upon a proposed 10.35% ROE 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. SWEPCo requested that rates become effective in June 2022.

APSC staff filed testimony supporting a $47 million annual increase in base rates based upon a ROE of 9.3% while other intervenors recommended a ROE ranging from 8.75% to 9.25%. The primary differences between SWEPCo's requested annual increase in base rates and the APSC staff's recommendation include: (a) recovery of the Dolet Hills Power Station through 2046 with no debt or equity return, (b) a reduction in the proposed ROE with a capital structure of 55.5% debt and 44.5% common equity and (c) lower depreciation rates. The APSC staff also recommended future generating facility retirements be treated similar to the Dolet Hills Power Station recommendation of recovery with no debt or equity return. Also, an intervenor recommended no debt or equity return on the Pirkey Power Plant after its retirement, which is currently expected to be in 2023. SWEPCo filed rebuttal testimony in January 2022 revising the requested annual increase in Arkansas base rates to $81 million with rates to be effective in June 2022. A hearing was held at the APSC in March 2022.If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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. LPSC staff testimony is due to the LPSC in May 2022 and an order is expected before the end of 2022If 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 $418 million as of March 31, 2022, of which $96 million, $141 million and $181 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. SWEPCo is currently recovering the fuel costs at an interim carrying charge of 0.3%. In April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05%, which has been supported by APSC staff. Various other parties have recommended recovery periods ranging from 5-20 years with a carrying charge of 1.65%. SWEPCo is awaiting a decision from the APSC.The prudence of these fuel costs is expected to be addressed in a separate proceeding.

In March 2021, the LPSC approved a special order granting a temporary modification to the FAC 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.

Independence Energy Connection Project (Applies to AEP)

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

In September 2021, PJM notified Transource Energy that the IEC was suspended to allow for the regulatory and related appeals process to proceed in an orderly manner without breaching milestone dates in the project agreement. PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. As of March 31, 2022, AEP's share of IEC capital expenditures was approximately $82 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 Consumer's Council 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 Ohio Consumer's Council 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.Management believes its financial statements adequately address the impact of the February 2022 complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2021 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP and AEP Texas)

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

AEP has $4 billion and $1 billion revolving credit facilities due in March 2027 and 2024, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of March 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 $400 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2022 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 308.7	April 2022 to March 2023
AEP Texas	2.2	July 2022

Guarantees of Equity Method Investees (Applies to AEP)

In 2019, AEP acquired Sempra Renewables LLC. The transaction resulted in the acquisition of a 50% ownership interest in five non-consolidated joint ventures and the acquisition of two tax equity partnerships. Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of March 31, 2022, the maximum potential amount of future payments associated with these guarantees was $142 million, with the last guarantee expiring in December 2037. The non-contingent liability recorded associated with these guarantees was $27 million, with an additional $2 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 March 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 activit conducted on their behalf. AEPSC also conducts power purchase-and-sale activity on behalf of PSO and SWEPCo, who are jointly and severall liable for activity conducted on their behalf.

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of March 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	$ 47.2
AEP Texas	11.0
APCo	6.1
I&M	4.1
OPCo	7.6
PSO	4.6
SWEPCo	5.2

Rockport Lease (Applies to AEP and I&M)

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

The trusts own undivided interests in Rockport Plant, Unit 2 and leases equal portions to AEGCo and I&M. In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in the Rockport Plant, Unit 2 effective at the end of the lease term in December 2022.In December 2021, AEGCo and I&M satisfied the necessary regulatory approvals to complete the acquisition.Upon receipt of the regulatory approval, the addition of the lessee forward purchase obligation resulted in the modified lease changing classification from operating to finance for AEGCo and I&M. The future minimum lease payments as of March 31, 2022, inclusive of the purchase obligation, were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2022	$ 248.7	$ 124.4
Total Future Minimum Lease Payments	$ 248.7	$ 124.4

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

The lease modification also created variable interests in the trusts that own the undivided interests in Rockport Plant, Unit 2 for AEGCo and I&M. Neither AEGCo nor I&M are the primary beneficiaries of the trusts because AEGCo nor I&M has the power to direct the most significant activities of the trusts. AEP and I&M's maximum exposure to loss associated with the trust is equal to the total future minimum lease payments, inclusive of the purchase obligation, as shown in the table above.

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 March 31, 2022, the maximum potential amount of future payments required under the guaranteed leases was $40 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 March 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 sheets.

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

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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

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

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

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

OPERATIONAL CONTINGENCIES

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

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

After the litigation proceeded at the district court and 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, with closing to occur as of the end of the Rockport Plant, Unit 2 lease in December 2022. The agreement is subject to customary closing conditions and as of the closing will result in a final settlement of, and release of claims in, the lease litigation. As a result, in May 2021, at the parties' request, the district court entered a stipulation and order dismissing the case without prejudice to plaintiffs asserting their claims in a re-filed action or a new action. The required regulatory approvals at the IURC and FERC have been obtained that would allow the closing to occur as of the end of the lease in December 2022. The IURC order approved a settlement agreement addressing the future use of Rockport Plant, Unit 2 as a capacity and energy resource and associated adjustments to I&M's Indiana retail rates, along with certain other matters. Management believes its financial statements appropriately reflect the resolution of the litigation.

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

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. AEP will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Litigation Related to Ohio House Bill 6 (HB 6)

In 2019, Ohio adopted and implemented HB 6 which benefits OPCo by authorizing rate recovery for certain costs including renewable energy contracts and OVEC's coal-fired generating units. OPCo engaged in lobbying efforts and provided testimony during the legislative process in connection with HB 6. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of an Ohio legislator and associates in connection with an alleged racketeering conspiracy involving the adoption of HB 6. After AEP learned of the criminal allegations against the Ohio legislator and others relating to HB 6, 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 United States District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. The amended complaint 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 United States District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The court has entered a scheduling order in the New York state court derivative action setting a deadline of April 29, 2022 for AEP to file a motion to dismiss the complaint and staying the case other than with respect to briefing the motion to dismiss. 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's motion to dismiss the amended complaint is due May 3, 2022 and discovery is stayed pending the district court's ruling on the motion to dismiss. The Ohio state court derivative action has been stayed until a decision by the federal district court on the motion to dismiss the amended complaint. 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 benefits to AEP from the passage of HB 6 and documents relating to AEP's financial processes and controls. AEP is cooperating fully with the SEC's subpoena. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this inquiry will have a material impact on financial condition, results of operations, or cash flows.

6. ACQUISITIONS AND ASSETS AND LIABILITIES HELD FOR SALE

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

ACQUISITIONS

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% 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. The nonaffiliated interest in Dry Lake is presented in Noncontrolling Interests on the balance sheets. Subsequent to close of the transaction, the noncontrolling interest made additional asset contributions of $16 million. As of March 31, 2022, AEP recognized approximately $145 million of Property, Plant and Equipment and approximately $35 million of Noncontrolling Interest on the balance sheets.

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

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs, on a fixed cost turn-key basis at completion. 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 Arkansa and Louisiana. The Oklahoma and Louisiana portions of the NCWF revenue requirement, net of PTC benefit, are recoverable through authorizec riders beginning at commercial operation and until such time as amounts are reflected in base rates. Recovery of the Arkansas portion of the NCWF revenue requirement is requested in SWEPCo's pending 2021 Arkansas Base Rate Case. The NCWF are subject to various regulatory performance requirements. If these performance requirements are not met, PSO and SWEPCo would recognize a regulatory liability to refund retail customers.

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

In September 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Maverick during its developmen and construction for $383 million, the second of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated th entity and simultaneously distributed the

Maverick assets in proportion to their undivided ownership interests. Maverick was placed in-service in September 2021.

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 March 31, 2022, PSO and SWEPCo had approximately $887 million and $1.1 billion, of gross Property, Plant and Equipment on the balance sheets, respectively, 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 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 immaterial as of March 31, 2022 and December 31, 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	
	March 31, 2022	December 31, 2021	March 31, 2022	December 31, 2021
	(in millions)			
Project				
Sundance	$ 12.6	$ 12.6	$ 15.0	$ 15.1
Maverick	18.0	18.0	21.6	21.6
Traverse	40.0	—	48.0	—
Total	$ 70.6	$ 30.6	$ 84.6	$ 36.7

ASSETS AND LIABILITIES HELD FOR SALE

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 to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value. The sale is subject to regulatory approvals from the FERC and KPSC. Clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and clearance from the Committee on Foreign Investment in the United States has been received.

Proposed Operations and Maintenance Agreement and Plant Ownership Agreement

KPCo currently operates and owns a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant with the remaining 50% owned by WPCo. The Stock Purchase Agreement is further contingent upon the issuance by the KPSC, WVPSC and FERC of orders regarding a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo.

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval of a proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement, pursuant to which WPCo would replace KPCo as the operator of the Mitchell Plant and KPCo employees at the Mitchell Plant would become employees of WPCo. Under this originally proposed Ownership Agreement, WPCo is obligated to purchase KPCo's 50% undivided interest in the Mitchell Plant on December 31, 2028 unless KPCo and WPCo have agreed to retire the Mitchell Plant earlier or, absent such agreement, if WPCo elects prior to December 31, 2027 to retire the Mitchell Plant on December 31, 2028. The Ownership Agreement provides that the purchase price for KPCo's 50% ownership interest in the Mitchell Plant will be determined through the mutual agreement of WPCo and KPCo (subject to approval from the KPSC and WVPSC) or through a fair market valuation determination conducted by independent appraisals, with offsets for estimated decommissioning costs and the cost of ELG investments made by WPCo, if KPCo and WPCo are unable to reach agreement as to the purchase price.

In January 2022, intervenor testimony was filed with the KPSC, recommending the KPSC either reject the new proposed Mitchell Plant Ownership Agreement or approve the agreement with certain modifications including a revision to the buyout provision that would set WPCo's Mitchell Plant purchase price at the greater of fair market value or net book value. The intervenor testimony also recommends the KPSC reject the proposed Mitchell Plant Operations and Maintenance Agreement, which the testimony stated should be modified to remove references to the Mitchell Plant Ownership Agreement. In February 2022, AEP filed rebuttal testimony with the KPSC opposing the intervenor testimony filed in January 2022. AEP's rebuttal testimony also discusses an alternative proposal to the fair market value provision included in the proposed Mitchell Plant Ownership Agreement. Under the alternative proposal, KPCo's and WPCo's interest in the Mitchell Plant would be divided by unit if the plant is not retired before the end of 2028 and a mutual agreement cannot be reached on a buyout price. Under the alternative proposal, mutual agreement on the buyout price or unit disposition would need to be finalized by May 2025, with a division of plant ownership by unit effective January 1, 2029, unless otherwise agreed. In March 2022, a hearing was held on the agreements with the KPSC. Following the hearing, KPCo amended its November 2021 filing with a new version of the Mitchell Plant Ownership Agreement that provided further details about the alternative proposal. As amended, the proposed Mitchell Plant Ownership Agreement creates procedures, subject to all required regulatory approvals, that provide the option for WPCo and KPCo to negotiate a sale of KPCo's interest in the Mitchell Plant to WPCo, split the Mitchell Plant units with additional agreements for KPCo to utilize WPCo's ELG assets, if necessary, or to agree on the procedures and timetable to retire one or both units. As amended, the proposed Mitchell Plant Ownership Agreement replaced certain aspects of the originally proposed agreement including the buyout provision at fair market value. A hearing on the amended filing was held on March 30, 2022. A decision from the KPSC is expected in the second quarter of 2022.

For the filing at the WVPSC, intervenor testimony filed in March 2022 and briefs filed in April 2022 recommended various clarifying modifications to the Mitchell Ownership Agreement and the Mitchell Operations and Maintenance Agreement. A decision from the WVPSC is expected in the second quarter of 2022.

The KPSC and WVPSC intervened in the FERC proceeding and have recommended that FERC dismiss or reject AEP's request, or defer ruling on AEP's request until both the retail commissions have rendered decisions. In February 2022, AEP filed a motion to withdraw its filing with the FERC, noting that AEP intends to re-file its request after the KPSC and WVPSC have reviewed the agreements.

Transfer of Ownership

In December 2021, Liberty, KPCo and KTCo sought approval from the FERC under Section 203 of the Federal Power Act for the sale. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission and generation 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. Liberty, KPCo and KTCo plan to respond to provide additional information in response to the letter. An order from the FERC is expected on the matter in the second quarter of 2022.

In January 2022, KPCo and Liberty filed a joint application requesting the KPSC authorize the transfer of ownership of KPCo to Liberty. In February 2022, certain intervenors filed testimony recommending that the KPSC not approve the transfer of ownership. If, however, the KPSC does approve the transfer, these intervenors recommend that the KPSC require AEP to compensate KPCo customers $578 million for alleged future increased costs and higher rates that the intervenors claim will exist under Liberty's ownership. AEP disagrees with the recommendation and filed rebuttal testimony in March 2022. AEP has committed to fund, through a reduction in Liberty's purchase price, $20 million of Liberty's commitment to provide $40 million of benefits to KPCo customers in bill reductions to help offset fuel costs. Intervenors also recommended imposing certain conditions on Liberty, including conditions related to recovering certain costs, inter-company agreement filing requirements, KPCo's capital structure and future generation resource planning processes and analyses. In addition, certain intervenors argue that the commission should not approve the new proposed Mitchell Plant Ownership Agreement and Mitchell Plant Operations and Maintenance Agreement, and that deciding the request to transfer ownership of KPCo should be separated from approval of the Mitchell agreements even though such approval is a condition to the transaction closing. AEP also disagrees with this argument. A hearing was held with the KPSC in March 2022. In April 2022, certain intervenors filed briefs with the KPSC in support of their original recommendations, including both recommendations for and against approval of the transfer of KPCo to Liberty. A final order is expected in the second quarter of 2022.

Subject to receipt of regulatory approval and resolution of the Mitchell ownership and operating issues disclosed above, the sale is expected to close in the second quarter of 2022 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction.

AEP expects to receive approximately $1.4 billion in cash, net of taxes and transaction fees. AEP plans to use the proceeds to eliminate forecasted equity needs in 2022 as the company invests in regulated renewables, transmission and other projects. AEP and AEPTCo expect the sale to have a one-time impact on after-tax earnings that is not material.

The Income Before Income Tax Expense (Benefit) and Equity Earnings of KPCo and KTCo were not material to AEP and AEPTCo for the thre months ended March 31, 2022 and 2021, respectively.

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 o AEP and AEPTCo are shown in the table below:

	AEP		AEPTCo	
	March 31, 2022	December 31, 2021	March 31, 2022	December 31, 2021
	(in millions)			
ASSETS				
Accounts Receivable and Accrued Unbilled Revenues	$ 75.3	$ 33.2	$ 1.8	$ 1.5
Fuel, Materials and Supplies	37.4	30.6	—	—
Property, Plant and Equipment, Net	2,323.1	2,302.7	165.8	165.3
Regulatory Assets	492.7	484.7	—	—
Other Classes of Assets that are not Major	44.1	68.5	2.3	1.1
Assets Held for Sale	$ 2,972.6	$ 2,919.7	$ 169.9	$ 167.9
LIABILITIES				
Accounts Payable	$ 57.5	$ 53.4	$ 1.1	$ 1.1
Long-term Debt Due Within One Year	200.0	200.0	—	—
Customer Deposits	34.2	32.4	—	—
Deferred Income Taxes	440.9	441.6	15.8	15.4
Long-term Debt	903.2	903.1	—	—
Regulatory Liabilities and Deferred Investment Tax Credits	140.2	148.1	7.8	7.6
Other Classes of Liabilities that are not Major	97.7	102.3	2.9	3.5
Liabilities Held for Sale	$ 1,873.7	$ 1,880.9	$ 27.6	$ 27.6

7. BENEFIT PLANS

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

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

Components of Net Periodic Benefit Cost

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

AEP

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 30.8	$ 32.3	$ 1.8	$ 2.4
Interest Cost	37.0	34.3	7.3	7.6
Expected Return on Plan Assets	(63.4)	(57.5)	(27.5)	(22.8)
Amortization of Prior Service Credit	—	—	(17.8)	(17.7)
Amortization of Net Actuarial Loss	15.8	25.4	—	—
Net Periodic Benefit Cost (Credit)	$ 20.2	$ 34.5	$ (36.2)	$ (30.5)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.8	$ 3.0	$ 0.1	$ 0.2
Interest Cost	3.0	2.8	0.6	0.6
Expected Return on Plan Assets	(5.3)	(4.9)	(2.3)	(1.9)
Amortization of Prior Service Credit	—	—	(1.5)	(1.5)
Amortization of Net Actuarial Loss	1.3	2.1	—	—
Net Periodic Benefit Cost (Credit)	$ 1.8	$ 3.0	$ (3.1)	$ (2.6)

APCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.9	$ 3.0	$ 0.2	$ 0.3
Interest Cost	4.4	4.1	1.2	1.2
Expected Return on Plan Assets	(8.1)	(7.3)	(4.1)	(3.4)
Amortization of Prior Service Credit	—	—	(2.6)	(2.6)
Amortization of Net Actuarial Loss	1.8	3.0	—	—
Net Periodic Benefit Cost (Credit)	$ 1.0	$ 2.8	$ (5.3)	$ (4.5)

I&M

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 4.0	$ 4.4	$ 0.2	$ 0.3
Interest Cost	4.2	4.0	0.8	0.9
Expected Return on Plan Assets	(8.0)	(7.2)	(3.4)	(2.8)
Amortization of Prior Service Credit	—	—	(2.4)	(2.4)
Amortization of Net Actuarial Loss	1.8	2.9	—	—
Net Periodic Benefit Cost (Credit)	$ 2.0	$ 4.1	$ (4.8)	$ (4.0)

OPCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.7	$ 2.9	$ 0.2	$ 0.2
Interest Cost	3.4	3.1	0.7	0.8
Expected Return on Plan Assets	(6.2)	(5.6)	(3.0)	(2.4)
Amortization of Prior Service Credit	—	—	(1.8)	(1.8)
Amortization of Net Actuarial Loss	1.4	2.2	—	—
Net Periodic Benefit Cost (Credit)	$ 1.3	$ 2.6	$ (3.9)	$ (3.2)

PSO

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 1.9	$ 1.9	$ 0.1	$ 0.2
Interest Cost	1.8	1.7	0.4	0.4
Expected Return on Plan Assets	(3.4)	(3.1)	(1.5)	(1.3)
Amortization of Prior Service Credit	—	—	(1.1)	(1.1)
Amortization of Net Actuarial Loss	0.7	1.3	—	—
Net Periodic Benefit Cost (Credit)	$ 1.0	$ 1.8	$ (2.1)	$ (1.8)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.6	$ 2.9	$ 0.1	$ 0.1
Interest Cost	2.3	2.1	0.5	0.5
Expected Return on Plan Assets	(3.7)	(3.4)	(1.9)	(1.5)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.0	1.5	—	—
Net Periodic Benefit Cost (Credit)	$ 2.2	$ 3.1	$ (2.6)	$ (2.2)

8. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

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

The tables below represent AEP's reportable segment income statement information for the three months ended March 31, 2022 and 2021 and reportable segment balance sheet information as of March 31, 2022 and December 31, 2021.

	Three Months Ended March 31, 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	$ 2,646.8	$ 1,242.2	$ 83.4	$ 609.5	$ 10.7	$ —	$ 4,592.6
Other Operating Segments	40.6	4.6	328.0	9.8	9.2	(392.2)	—
Total Revenues	$ 2,687.4	$ 1,246.8	$ 411.4	$ 619.3	$ 19.9	$ (392.2)	$ 4,592.6
Net Income (Loss)	$ 299.2	$ 152.8	$ 173.7	$ 116.0	$ (23.6)	$ —	$ 718.1

	Three Months Ended March 31, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 2,504.5	$ 1,082.3	$ 87.9	$ 601.7	$ 4.7	$ —	$ 4,281.1
Other Operating Segments	32.8	5.8	289.1	32.5	8.2	(368.4)	—
Total Revenues	$ 2,537.3	$ 1,088.1	$ 377.0	$ 634.2	$ 12.9	$ (368.4)	$ 4,281.1
Net Income (Loss)	$ 271.4	$ 114.4	$ 173.2	$ 38.2	$ (18.4)	$ —	$ 578.8

	March 31, 2022						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets (d)	$ 48,073.4	$ 21,413.9	$ 14,083.9	$ 4,790.7	$ 6,743.6 (b)	$ (5,274.1) (c)	$ 89,831.4

	December 31, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
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

(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 6 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 ar 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 utilitiesThe 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 ParentWhile not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

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

	Three Months Ended March 31, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 75.7	$ —	$ —	$ 75.7
Sales to AEP Affiliates	324.7	—	—	324.7
Total Revenues	$ 400.4	$ —	$ —	$ 400.4
Net Income	$ 155.4	$ — (a)	$ —	$ 155.4

	Three Months Ended March 31, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 76.0	$ —	$ —	$ 76.0
Sales to AEP Affiliates	285.6	—	—	285.6
Other Revenues	0.1	—	—	0.1
Total Revenues	$ 361.7	$ —	$ —	$ 361.7
Net Income	$ 151.7	$ — (a)	$ —	$ 151.7

	March 31, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets (d)	$ 12,768.6	$ 4,396.3 (b)	$ (4,450.5) (c)	$ 12,714.4

	December 31, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets (d)	$ 12,564.3	$ 4,389.5 (b)	$ (4,429.4) (c)	$ 12,524.4

(a) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos.
(b) Includes the elimination of AEPTCo Parent's investments in State Transcos.
(c) Primarily relates to the elimination of Notes Receivable from the State Transcos.
(d) Amount includes Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

9. DERIVATIVES AND HEDGING

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments
March 31, 2022

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	241.4	—	13.2	5.3	2.7	4.5	2.3
Natural Gas	MMBtus	45.6	—	—	—	—	—	3.7
Heating Oil and Gasoline	Gallons	5.4	1.4	0.8	0.5	1.1	0.6	0.8
Interest Rate	USD	$ 108.6	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,150.0	$ —	$ —	$ —	$ —	$ —	$ —

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 $655 million and $263 million as of March 31, 2022 and December 31, 2021, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $0 and $3 million as of March 31, 2022 and December 31, 2021, respectively. The netted cash collateral from third-parties against short-term and long-term risk management assets and netted cash collateral paid to third-parties against short-term and long-term risk management liabilities were immaterial for the Registrant Subsidiaries as of March 31, 2022 and December 31, 2021.

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

AEP

	March 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)	$ 965.8	$ 420.5	$ —	$ 1,386.3	$ (1,075.6)	$ 310.7
Long-term Risk Management Assets	497.0	140.4	3.9	641.3	(380.5)	260.8
Total Assets	1,462.8	560.9	3.9	2,027.6	(1,456.1)	571.5
Current Risk Management Liabilities (e)	754.6	35.8	2.3	792.7	(662.7)	130.0
Long-term Risk Management Liabilities	346.6	13.5	79.5	439.6	(139.2)	300.4
Total Liabilities	1,101.2	49.3	81.8	1,232.3	(801.9)	430.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 361.6	$ 511.6	$ (77.9)	$ 795.3	$ (654.2)	$ 141.1

	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	March 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	$ 1.5	$ (1.3)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	1.5	(1.3)	0.2
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1.5	$ (1.3)	$ 0.2

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	March 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	$ 10.8	$ (3.8)	$ 7.0
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.5	(0.5)	—
Total Assets	11.3	(4.3)	7.0
Other Current Liabilities - Current Risk Management Liabilities	3.2	(3.0)	0.2
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.5	(0.5)	—
Total Liabilities	3.7	(3.5)	0.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ 7.6	$ (0.8)	$ 6.8

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
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	47.7	(5.7)	42.0
Other Current Liabilities - Current Risk Management Liabilities	7.2	(6.4)	0.8
Deferred Credits and Other Noncurrent Liabilities - 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	March 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	$ 4.6	$ (3.1)	$ 1.5
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.3	(0.3)	—
Total Assets	4.9	(3.4)	1.5
Current Risk Management Liabilities	2.9	(2.5)	0.4
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.3	(0.3)	—
Total Liabilities	3.2	(2.8)	0.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 1.7	$ (0.6)	$ 1.1

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
Deferred Charges and Other Noncurrent Assets - 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
Deferred Credits and Other Noncurrent Liabilities - 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	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)
	March 31, 2022		
		(in millions)	
Prepayments and Other Current Assets - Current Risk Management Assets	$ 1.1	$ (1.0)	$ 0.1
Long-term Risk Management Assets	—	—	—
Total Assets	1.1	(1.0)	0.1
Current Risk Management Liabilities	1.5	—	1.5
Long-term Risk Management Liabilities	67.0	—	67.0
Total Liabilities	68.5	—	68.5
Total MTM Derivative Contract Net Liabilities	$ (67.4)	$ (1.0)	$ (68.4)

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	$ 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	March 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	$ 7.9	$ (1.2)	$ 6.7
Long-term Risk Management Assets	—	—	—
Total Assets	7.9	(1.2)	6.7
Current Risk Management Liabilities	0.8	(0.7)	0.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.8	(0.7)	0.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 7.1	$ (0.5)	$ 6.6

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	$ 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	March 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	$ 16.7	$ (0.9)	$ 15.8
Long-term Risk Management Assets	—	—	—
Total Assets	16.7	(0.9)	15.8
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 16.5	$ (0.7)	$ 15.8

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
Deferred Charges and Other Noncurrent Assets - 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 $1.4 million and $6 million as of March 31, 2022 and December 31, 2021, respectively, classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.
(e) Amount excludes Risk Management Liabilities of $0 and $0.1 million as of March 31, 2022 and December 31, 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended March 31, 2022						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Generation & Marketing Revenues	$ 152.3	$ —	$ —	$ —	$ —	$ —	$ —
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	(0.1)	—	—	—
Purchased Electricity for Resale	1.5	—	1.4	—	—	—	—
Other Operation	0.6	0.2	—	0.1	0.1	0.1	0.1
Maintenance	0.8	0.2	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	23.6	—	(0.1)	(1.6)	23.9	3.6	(2.1)
Regulatory Liabilities (a)	36.5	0.9	(1.4)	1.7	—	12.7	20.9
Total Gain on Risk Management Contracts	$ 215.3	$ 1.3	$ 0.1	$ 0.2	$ 24.1	$ 16.5	$ 19.0

Location of Gain (Loss)	Three Months Ended March 31, 2021						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 0.2	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(0.4)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.2	—	—	—	—
Purchased Electricity for Resale	0.4	—	0.4	—	—	—	—
Other Operation	0.3	0.1	—	—	0.1	—	—
Maintenance	0.5	0.1	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	6.4	—	—	(0.9)	6.6	—	0.8
Regulatory Liabilities (a)	22.0	0.4	3.4	(3.2)	2.9	11.2	6.2
Total Gain (Loss) on Risk Management Contracts	$ 29.4	$ 0.6	$ 4.1	$ (4.0)	$ 9.7	$ 11.3	$ 7.1

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

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies (Applies to AEP)

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts net income during the period of change.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income.

The following table shows the impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Liabilities		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Liabilities	
	March 31, 2022	December 31, 2021	March 31, 2022	December 31, 2021
	(in millions)			
Long-term Debt (a) (b)	$ (906.0)	$ (952.3)	$ 38.2	$ (8.5)

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.
(b) Amounts include $(44) million and $(46) million as of March 31, 2022 and December 31, 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:

	Three Months Ended March 31,	
	2022	2021
	(in millions)	
Gain (Loss) on Interest Rate Contracts:		
Fair Value Hedging Instruments (a)	$ (44.8)	$ (33.2)
Fair Value Portion of Long-term Debt (a)	44.8	33.2

(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, 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 three months ended March 31, 2022 and 2021, AEP applied cash flow hedging to outstanding power derivatives and the Registrant Subsidiaries did not.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2022 AEP applied cash flow hedging to outstanding interest rate derivatives and the Registrant Subsidiaries did not. During the three months ended March 31, 2021, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on AEP's Balance Sheets

	March 31, 2022		December 31, 2021	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ 404.0	$ (13.6)	$ 163.7	$ (21.3)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	303.9	(2.9)	106.7	(3.3)

As of March 31, 2022 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 108 months and 105 months for commodity and interest rate hedges, respectively.

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

	March 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	$ (1.0)	$ (1.0)	$ (1.3)	$ (1.1)
APCo	7.3	0.8	7.5	0.8
I&M	(6.3)	(1.6)	(6.7)	(1.6)
SWEPCo	1.3	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 $27 million and $9 million as of March 31, 2022 and December 31, 2021, respectively. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of March 31, 2022 and December 31, 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 $82 million and $40 million as of March 31, 2022 and December 31, 2021, respectively. There was no cash collateral posted as of March 31, 2022 and December 31, 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 March 31, 2022 and December 31, 2021.

Cross-Default Triggers (Applies to AEP, APCo, I&M and SWEPCo)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. AEP had derivative liabilities subject to cross-default provisions in a net liability position of $167 million and $76 million and no cash collateral posted as of March 31, 2022 and December 31, 2021, respectively, after considering contractual netting arrangements. 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 March 31, 2022 and December 31, 2021 were not material.

Warrants Held in Investee (Applies to AEP)

AEP holds an investment in ChargePoint, which completed an initial public offering (IPO) in February 2021 via a reverse merger with a public special purpose acquisition company. AEP's interests in ChargePoint consisted of a noncontrolling equity interest of common shares, which were accounted for at their fair value of $30 million as of March 31, 2022, and common share warrants. AEP recorded unrealized gains of $1 million and $27 million associated with the common shares for the three months ended March 31, 2022 and 2021, respectively, presented in Other Income (Expense) on AEP's statements of income.

Management has determined the common share warrants are derivative instruments based on the accounting guidance for "Derivatives and Hedging". As of March 31, 2022 and December 31, 2021, the warrants were valued at $15 million and $15 million, respectively, and were recorded in Deferred Charges and Other Noncurrent Assets on AEP's balance sheets.AEP recognized an unrealized gain of $1 million and unrealized loss of $10 million associated with the warrants for the three months ended March 31, 2022 and 2021, respectively, presented in Other Income (Expense) on AEP's statements of income.

Management utilized a Black-Scholes options pricing model to value the warrants as of March 31, 2022 and December 31, 2021.There was an observable publicly traded stock price to use in the Black-Scholes options pricing model, which resulted in the warrants being categorized as Level 2 as of March 31, 2022 and December 31, 2021. The common shares are categorized as Level 1 based on the observable publicly traded stock price. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 10 for additional information.

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

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

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

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

Assets in the nuclear trusts, cash and cash equivalents, other temporary investments restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

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

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

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

	March 31, 2022		December 31, 2021	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
		(in millions)		
AEP (a)(b)(c)	$ 33,864.1	$ 34,144.5	$ 33,454.5	$ 37,564.7
AEP Texas	5,170.6	5,123.4	5,180.8	5,663.8
AEPTCo	4,344.5	4,301.5	4,343.9	4,968.2
APCo	4,927.2	5,339.9	4,938.9	6,037.1
I&M	3,171.7	3,282.6	3,195.0	3,748.0
OPCo	2,969.0	2,965.6	2,968.5	3,437.5
PSO	2,413.6	2,412.6	1,913.5	2,163.7
SWEPCo	3,394.1	3,342.4	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 $950 million and $1.7 billion as of March 31, 2022 and December 31, 2021, respectively. See "Equity Units" section of Note 12 for additional information.
(b) The book value amounts exclude Long-term Debt of $1.1 billion and $1.1 billion as of March 31, 2022 and December 31, 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.
(c) The fair value amounts exclude Long-term Debt of $1.1 billion and $1.2 billion as of March 31, 2022 and December 31, 2021, respectively, related to KPCo. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

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

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

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

	March 31, 2022			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash (a)	$ 49.9	$ —	$ —	$ 49.9
Other Cash Deposits	9.5	—	—	9.5
Fixed Income Securities – Mutual Funds (b)	151.5	—	(4.5)	147.0
Equity Securities – Mutual Funds	19.7	32.3	—	52.0
Total Other Temporary Investments and Restricted Cash	$ 230.6	$ 32.3	$ (4.5)	$ 258.4

Other Temporary Investments and Restricted Cash	December 31, 2021 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:

	Three Months Ended March 31, 2022	2021
	(in millions)	
Proceeds from Investment Sales	$ 3.9	$ 5.5
Purchases of Investments	0.8	0.7
Gross Realized Gains on Investment Sales	0.3	0.1
Gross Realized Losses on Investment Sales	0.1	—

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

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

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

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies debt securities in the trust funds as available-for-sale due to their long-term purpose.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI.

The following is a summary of nuclear trust fund investments:

	March 31, 2022			December 31, 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	$ 21.8	$ —	$ —	$ 84.7	$ —	$ —
Fixed Income Securities:						
United States Government	1,169.6	13.5	(22.3)	1,156.4	66.3	(7.9)
Corporate Debt	69.4	0.1	(4.0)	76.7	6.7	(2.1)
State and Local Government	7.2	0.2	(0.1)	7.3	0.4	(0.1)
Subtotal Fixed Income Securities	1,246.2	13.8	(26.4)	1,240.4	73.4	(10.1)
Equity Securities - Domestic (a)	2,410.4	1,763.5	—	2,541.9	1,901.3	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,678.4	$ 1,777.3	$ (26.4)	$ 3,867.0	$ 1,974.7	$ (10.1)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.8 billion and $1.9 billion and unrealized losses of $5 million and $4 million as of March 31, 2022 and December 31, 2021, respectively.

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

	Three Months Ended March 31, 2022	2021
	(in millions)	
Proceeds from Investment Sales	$ 493.5	$ 320.0
Purchases of Investments	507.7	336.9
Gross Realized Gains on Investment Sales	5.8	5.4
Gross Realized Losses on Investment Sales	7.2	4.2

The base cost of fixed income securities was $1.2 billion and $1.2 billion as of March 31, 2022 and December 31, 2021, respectively. The base cost of equity securities was $647 million and $641 million as of March 31, 2022 and December 31, 2021, respectively.

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

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 342.3
After 1 year through 5 years	427.3
After 5 years through 10 years	232.4
After 10 years	244.2
Total	$ 1,246.2

Fair Value Measurements of Financial Assets and Liabilities

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

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 49.9	$ —	$ —	$ —	$ 49.9
Other Cash Deposits (a)	—	—	—	9.5	9.5
Fixed Income Securities – Mutual Funds	147.0	—	—	—	147.0
Equity Securities – Mutual Funds (b)	52.0	—	—	—	52.0
Total Other Temporary Investments and Restricted Cash	248.9	—	—	9.5	258.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (d) (i)	26.1	1,194.1	223.7	(1,391.1)	52.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	519.6	35.4	(40.2)	514.8
Interest Rate Hedges	—	3.9	—	—	3.9
Total Risk Management Assets	26.1	1,717.6	259.1	(1,431.3)	571.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.2	—	—	7.6	21.8
Fixed Income Securities:					
United States Government	—	1,169.6	—	—	1,169.6
Corporate Debt	—	69.4	—	—	69.4
State and Local Government	—	7.2	—	—	7.2
Subtotal Fixed Income Securities	—	1,246.2	—	—	1,246.2
Equity Securities – Domestic (b)	2,410.4	—	—	—	2,410.4
Total Spent Nuclear Fuel and Decommissioning Trusts	2,424.6	1,246.2	—	7.6	3,678.4
Other Investments (h)	30.1	15.5	—	—	45.6
Total Assets	$ 2,729.7	$ 2,979.3	$ 259.1	$ (1,414.2)	$ 4,553.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d) (j)	$ 8.0	$ 896.7	$ 177.5	$ (736.8)	$ 345.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	43.3	0.1	(40.2)	3.2
Interest Rate Hedges	—	0.1	—	—	0.1
Fair Value Hedges	—	81.7	—	—	81.7
Total Risk Management Liabilities	$ 8.0	$ 1,021.8	$ 177.6	$ (777.0)	$ 430.4

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
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 and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 39.9	$ —	$ —	$ —	$ 39.9
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	1.5	—	(1.3)	0.2
Total Assets	$ 39.9	$ 1.5	$ —	$ (1.3)	$ 40.1

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(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 and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 10.0	$ —	$ —	$ —	$ 10.0
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	4.3	7.0	(4.3)	7.0
Total Assets	$ 10.0	$ 4.3	$ 7.0	$ (4.3)	$ 17.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.3	$ 0.4	$ (3.5)	$ 0.2

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.8	$ 2.1	$ (3.4)	$ 1.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14.2	—	—	7.6	21.8
Fixed Income Securities:					
United States Government	—	1,169.6	—	—	1,169.6
Corporate Debt	—	69.4	—	—	69.4
State and Local Government	—	7.2	—	—	7.2
Subtotal Fixed Income Securities	—	1,246.2	—	—	1,246.2
Equity Securities - Domestic (b)	2,410.4	—	—	—	2,410.4
Total Spent Nuclear Fuel and Decommissioning Trusts	2,424.6	1,246.2	—	7.6	3,678.4
Total Assets	$ 2,424.6	$ 1,249.0	$ 2.1	$ 4.2	$ 3,679.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.1	$ 1.1	$ (2.8)	$ 0.4

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 and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 1.1	$ —	$ (1.0)	$ 0.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (g)	$ —	$ —	$ 68.5	$ —	$ 68.5

December 31, 2021

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

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.6	$ 7.3	$ (1.2)	$ 6.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.8	$ (0.7)	$ 0.1

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	$ 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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.8	$ 15.9	$ (0.9)	$ 15.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.2	$ (0.2)	$ —

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 March 31, 2022 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $14 million in 2022 and $4 million in periods 2023-2025; Level 2 matures $96 million in 2022, $188 million in periods 2023-2025, $10 million in periods 2026-2027 and $4 million in periods 2028-2033; Level 3 matures $37 million in 2022, $8 million in periods 2023-2025, $13 million in periods 2026-2027 and $(11) million in periods 2028-2033. 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 9 for additional information.

(i) Amount excludes Risk Management Assets of $1.4 million and $6 million as of March 31, 2022 and December 31, 2021, respectively, classified as Assets Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.

(j) Amount excludes Risk Management Liabilities of $0 and $0.1 million as of March 31, 2022 and December 31, 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.

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

Three Months Ended March 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)	18.2	(2.9)	3.8	0.5	12.1	9.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(19.0)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	19.3	—	—	—	—	—
Settlements	(51.6)	(32.4)	(2.3)	1.4	(19.8)	(16.2)
Transfers into Level 3 (d) (e)	2.5	—	—	—	—	—
Transfers out of Level 3 (e)	2.9	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	7.4	0.2	0.2	22.1	2.1	11.2
Assets and Liabilities Held for Sale related to KPCo (g)	4.5	—	—	—	—	—
Balance as of March 31, 2022	$ 81.5	$ 6.6	$ 1.0	$ (68.5)	$ 6.5	$ 15.7

Three Months Ended March 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)	19.8	2.1	0.3	—	9.3	6.1
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(21.3)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	3.1	—	—	—	—	—
Settlements	(47.9)	(15.6)	(1.4)	2.7	(16.3)	(8.2)
Transfers into Level 3 (d) (e)	0.5	—	—	—	—	—
Transfers out of Level 3 (e)	(33.0)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	7.3	0.8	(0.3)	3.6	2.2	1.0
Balance as of March 31, 2021	$ 41.8	$ 6.6	$ 0.7	$ (104.0)	$ 5.5	$ 0.5

(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) Amount excludes Risk Management Assets classified as Assets Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.

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

AEP

Significant Unobservable Inputs
March 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 223.3	$ 169.5	Discounted Cash Flow	Forward Market Price (a)	$ 12.79	$ 119.45	$ 42.15
Natural Gas Contracts	10.1	—	Discounted Cash Flow	Forward Market Price (b)	2.58	6.01	5.05
FTRs	25.7	8.1	Discounted Cash Flow	Forward Market Price (a)	(41.14)	13.46	(0.08)
Total	$ 259.1	$ 177.6					

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 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	77.5	13.0	Discounted Cash Flow	Forward Market Price (a)	(23.93)	26.38	0.86
Total	$ 245.5	$ 148.2					

APCo

Significant Unobservable Inputs
March 31, 2022

	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	$ 44.99	$ 66.21	$ 55.42
FTRs	7.0	0.2	Discounted Cash Flow	Forward Market Price	0.15	11.19	1.05
Total	$ 7.0	$ 0.4					

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

Significant Unobservable Inputs
March 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 0.1	Discounted Cash Flow	Forward Market Price	$ 44.99	$ 66.21	$ 55.42
FTRs	2.1	1.0	Discounted Cash Flow	Forward Market Price	(1.32)	11.50	0.41
Total	$ 2.1	$ 1.1					

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

Significant Unobservable Inputs
March 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 68.5	Discounted Cash Flow	Forward Market Price	$ 15.77	$ 83.20	$ 38.10

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

Significant Unobservable Inputs
March 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 7.3	$ 0.8	Discounted Cash Flow	Forward Market Price	$ (41.14)	$ 11.59	$ (3.69)

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

Significant Unobservable Inputs
March 31, 2022

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ 10.1	$ —	Discounted Cash Flow	Forward Market Price (b)	$ 5.23	$ 6.01	$ 5.51
FTRs	5.8	0.2	Discounted Cash Flow	Forward Market Price (a)	(41.14)	11.59	(3.69)
Total	$ 15.9	$ 0.2					

December 31, 2021

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range 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.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of March 31, 2022 and December 31, 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)

11. INCOME TAXES

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

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2022 and 2021, adjusted for tax expense associated with certain discrete items.

The Registrants include the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, the Registrants recognize the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by the Registrant's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an annual estimated ETR.

The ETR for each of the Registrants are included in the following tables:

	Three Months Ended March 31, 2022							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	1.5 %	0.3 %	2.6 %	2.9 %	1.6 %	0.7 %	0.6 %	2.3 %
Tax Reform Excess ADIT Reversal	(6.6)%	(2.0)%	0.3 %	(5.8)%	(17.3)%	(7.8)%	(15.3)%	(4.9) %
Production and Investment Tax Credits	(8.0)%	(0.2)%	— %	—%	(1.4)%	—%	(26.2)%	(23.1) %
Flow Through	0.3 %	0.3 %	0.3 %	1.7 %	(1.9)%	0.9 %	0.6 %	(0.6) %
AFUDC Equity	(0.9)%	(0.9)%	(1.6) %	(0.7)%	(0.6)%	(0.6)%	(0.7)%	(0.5) %
Discrete Tax Adjustments	(0.6)%	—%	— %	(0.6)%	—%	—%	—%	— %
Other	0.2 %	(0.1)%	— %	—%	(0.2)%	—%	(0.8)%	0.6 %
Effective Income Tax Rate	6.9 %	18.4 %	22.6 %	18.5 %	1.2 %	14.2 %	(20.8)%	(5.2) %

	Three Months Ended March 31, 2021							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.3 %	1.4 %	2.7 %	3.2 %	1.3 %	0.7 %	4.7 %	(0.8) %
Tax Reform Excess ADIT Reversal	(9.2)%	(7.8)%	0.3 %	(18.0)%	(17.9)%	(9.7)%	(24.7)%	(5.9) %
Production and Investment Tax Credits	(5.5)%	(0.3)%	— %	—%	(1.7)%	—%	(8.2)%	(5.1) %
Flow Through	0.3 %	0.3 %	0.2 %	1.6 %	(1.0)%	1.1 %	0.6 %	(0.7) %
AFUDC Equity	(0.9)%	(1.4)%	(1.7) %	(1.1)%	(0.2)%	(1.1)%	(0.5)%	(0.4) %
Parent Company Loss Benefit	—%	—%	(1.9) %	(2.9)%	(2.5)%	—%	—%	— %
Discrete Tax Adjustments	0.5 %	—%	— %	—%	—%	(4.0)%	—%	— %
Other	0.1 %	0.1 %	0.1 %	0.1 %	—%	0.2 %	(0.9)%	0.1 %
Effective Income Tax Rate	8.6 %	13.3 %	20.7 %	3.9 %	(1.0)%	8.2 %	(8.0)%	8.2 %

Federal and State Income Tax Audit Status

In the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 through 2017 federal returns. In the first quarter of 2020, the IRS notified AEP that it was beginning an examination of these amended returns, including the net operating loss carryback to 2015 that originated in the 2017 return. As of March 31, 2022, the IRS has not issued any proposed adjustment and has accepted the 2014 amended return as filed.AEP has agreed to extend the statute of limitations on the 2017 tax return to December 31, 2022 to allow time for the audit to be completed and the Congressional Joint Committee on Taxation to approve the associated refund claim.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and AEP and subsidiaries are currently under examination in several state and local jurisdictions. 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.

12. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

At-the-Market (ATM) Program

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

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	March 31, 2022	December 31, 2021
	(in millions)	
Senior Unsecured Notes	$ 27,454.6	$ 27,497.3
Pollution Control Bonds	1,804.8	1,804.5
Notes Payable	186.4	211.3
Securitization Bonds	579.6	603.5
Spent Nuclear Fuel Obligation (a)	281.4	281.3
Junior Subordinated Notes (b)	2,373.4	2,373.0
Other Long-term Debt	1,183.9	683.6
Total Long-term Debt Outstanding	33,864.1	33,454.5
Long-term Debt Due Within One Year (c)	3,008.4	2,153.8
Long-term Debt (d)	$ 30,855.7	$ 31,300.7

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $328 million and $329 million as of March 31, 2022 and December 31, 2021, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See "Equity Units" section below for additional information.
(c) Amount excludes $200 million and $200 million as of March 31, 2022 and December 31, 2021, respectively, of Long-term Debt Due Within One Year classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.
(d) Amount excludes $903 million and $903 million as of March 31, 2022 and December 31, 2021, respectively, of Long-term Debt classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2022 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
PSO	Other Long-term Debt	$ 500.0	Variable	2022
Non-Registrant:				
Transource Energy	Other Long-term Debt	1.0	Variable	2023
Total Issuances		$ 501.0		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**	**(%)**	
AEP Texas	Securitization Bonds	$ 11.4	2.06	2025
APCo	Securitization Bonds	12.7	2.01	2023
I&M	Notes Payable	1.3	Variable	2022
I&M	Notes Payable	1.1	Variable	2022
I&M	Notes Payable	4.6	Variable	2023
I&M	Notes Payable	3.5	Variable	2024
I&M	Notes Payable	6.5	Variable	2025
I&M	Notes Payable	6.2	0.93	2025
I&M	Other Long-term Debt	0.6	6.00	2025
PSO	Other Long-term Debt	0.1	3.00	2027
SWEPCo	Notes Payable	1.6	4.58	2032
Non-Registrant:				
Transource Energy	Senior Unsecured Notes	1.4	2.75	2050
Total Retirements and Principal Payments		$ 51.0		

Long-term Debt Subsequent Event

In April 2022, I&M retired $5 million of Notes Payable related to DCC Fuel.

In April 2022, AEP remarketed $65 million of Pollution Control Bonds related to WPCo.

Equity Units (Applies to AEP)

2020 Equity Units

In August 2020, AEP issued 17 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $850 million. Net proceeds from the issuance were approximately $833 million. The proceeds were used to support AEP's overall capital expenditure plans.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes (notes) due in 2025 and a forward equity purchase contract which settles after three years in 2023. The notes are expected to be remarketed in 2023, at which time the interest rate will reset at the then current market rate. Investors may choose to remarket their notes to receive the remarketing proceeds and use those funds to settle the forward equity purchase contract, or accept the remarketed debt and use other funds for the equity purchase. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the principal. The Equity Units carry an annual distribution rate of 6.125%, which is comprised of a quarterly coupon rate of interest of 1.30% and a quarterly forward equity purchase contract payment of 4.825%.

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

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

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

At the time of issuance, the $850 million of notes were recorded within Long-term Debt on the balance sheets. The present value of the purchase contract payments of $121 million were recorded in Deferred Credits and Other Noncurrent Liabilities with a current portion in Other Current Liabilities at the time of issuance, representing the obligation to make forward equity contract payments, with an offsetting reduction to Paid-in Capital. The difference between the face value and present value of the purchase contract payments will be accreted to Interest Expense on the statements of income over the three year period ending in 2023. The liability recorded for the contract payments is considered non-cash and excluded from the statements of cash flows. Until settlement of the forward equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method. The maximum amount of shares AEP will be required to issue to settle the purchase contract is 10,205,100 shares (subject to an anti-dilution adjustment).

2019 Equity Units

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

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes (notes) due in 2024 and a forward equity purchase contract which 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 2.9% of consolidated tangible net assets as of March 31, 2022. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

Corporate Borrowing Program - AEP System (Applies to all Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries.The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC.The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of March 31, 2022 and December 31, 2021 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' activity and corresponding authorized borrowing limits for the three months ended March 31, 2022 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Borrowings from the Utility Money Pool as of March 31, 2022		Authorized Short-term Borrowing Limit	
				(in millions)				
AEP Texas	$ 264.7	$ —	$ 152.8	$ —	$ (262.2)		$ 500.0	
AEPTCo	388.4	14.5	253.1	3.2	(282.1)	(a)	820.0	(b)
APCo	227.9	20.8	114.6	20.0	(15.8)		500.0	
I&M	159.1	21.5	102.2	21.5	(52.1)		500.0	
OPCo	112.2	92.1	57.4	41.5	(55.7)		500.0	
PSO	211.8	432.5	94.8	403.6	(211.8)		400.0	
SWEPCo	215.6	156.6	201.9	109.7	(202.9)		400.0	

(a) Amount excludes $2 million of Advances to Affiliates classified as Assets Held for Sale on the AEPTCo balance sheet. See "Dispositions of KPCo and KTCo" section of Note 6 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 table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in th Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of March 31, 2022 and December 31, 2021 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the three months ended March 31, 2022 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of March 31, 2022
		(in millions)	
AEP Texas	$ 6.9	$ 6.8	$ 6.8
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 March 31, 2022 and December 31, 2021 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets.AEPTCo's direct borrowing and lending activity with AEP and corresponding authorized borrowing limit for the three months ended March 31, 2022 are described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of March 31, 2022	Loans to AEP as of March 31, 2022	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 37.0	$ 141.8	$ 4.3	$ 72.7	$ 37.0	$ —	$ 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:

	Three Months Ended March 31,	
	2022	2021
Maximum Interest Rate	1.00 %	0.40 %
Minimum Interest Rate	0.10 %	0.25 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Three Months Ended March 31,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Three Months Ended March 31,	
Company	2022	2021	2022	2021
AEP Texas	0.70 %	0.31 %	— %	— %
AEPTCo	0.66 %	0.31 %	0.60 %	0.28 %
APCo	0.55 %	0.28 %	0.62 %	0.36 %
I&M	0.63 %	0.31 %	0.62 %	0.30 %
OPCo	0.77 %	0.29 %	0.48 %	0.29 %
PSO	0.69 %	0.33 %	0.65 %	0.28 %
SWEPCo	0.98 %	0.28 %	0.55 %	0.38 %

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

	Three Months Ended March 31, 2022			Three Months Ended March 31, 2021		
Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	1.00 %	0.46 %	0.62 %	0.40 %	0.25 %	0.30 %
SWEPCo	1.00 %	0.46 %	0.62 %	0.40 %	0.25 %	0.30 %

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

Three Months Ended March 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	1.00 %	0.46 %	1.00 %	0.46 %	0.66 %	0.60 %
2021	0.86 %	0.25 %	0.86 %	0.25 %	0.31 %	0.31 %

Short-term Debt (Applies to AEP)

Outstanding short-term debt was as follows:

Company	Type of Debt	March 31, 2022 Outstanding Amount	March 31, 2022 Interest Rate (a)	December 31, 2021 Outstanding Amount	December 31, 2021 Interest Rate (a)
		(dollars in millions)			
AEP	Securitized Debt for Receivables (b)	$ 750.0	0.31 %	$ 750.0	0.19 %
AEP	Commercial Paper	1,880.3	0.97 %	1,364.0	0.34 %
AEP	Term Loan (c)	500.0	1.11 %	500.0	0.81 %
AEP	Term Loan	250.0	0.97 %	—	— %
	Total Short-term Debt	$ 3,380.3		$ 2,614.0	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) In March 2022, AEP extended the maturity date of the original 364-Day Term Loan to August 2022.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility which expire in September 2023 and 2024, respectively. As of March 31, 2022, the affiliated utility subsidiaries are in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
	(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	0.31 %	0.20 %
Net Uncollectible Accounts Receivable Written-Off	$ 7.4	$ 9.3

	March 31, 2022	December 31, 2021
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 948.4	$ 995.2
Short-term – Securitized Debt of Receivables	750.0	750.0
Delinquent Securitized Accounts Receivable	50.1	57.9
Bad Debt Reserves Related to Securitization	41.8	42.8
Unbilled Receivables Related to Securitization	237.1	307.1

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. 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. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreements were:

Company	March 31, 2022	December 31, 2021
	(in millions)	
APCo	$ 148.6	$ 153.1
I&M	178.0	156.9
OPCo	402.0	392.7
PSO	109.0	114.5
SWEPCo	139.9	153.0

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

Company	Three Months Ended March 31, 2022	2021
	(in millions)	
APCo	$ 1.3	$ 1.2
I&M	1.7	1.6
OPCo	7.4	1.3
PSO	0.9	0.7
SWEPCo	1.3	1.5

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

Company	Three Months Ended March 31, 2022	2021
	(in millions)	
APCo	$ 415.5	$ 362.4
I&M	513.4	478.8
OPCo	716.6	601.3
PSO	363.4	284.9
SWEPCo	394.5	384.4

13. PROPERTY, PLANT AND EQUIPMENT

The disclosure in this note applies to AEP, PSO and SWEPCo.

Asset Retirement Obligations

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal mining facilities. The discussion below summarizes significant changes to the Registrants ARO recorded in 2022 and should be read in conjunction with the Property, Plant and Equipment note within the 2021 Annual Report.

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 6 for additional information. Additionally, in March 2022, SWEPCo recorded a $13 million revision due to an increase in estimated ash pond closure costs at the Pirkey Power Plant and the Welsh Plant.

The following is a reconciliation of the aggregate carrying amounts of ARO for AEP, PSO and SWEPCo:

Company	ARO as of December 31, 2021	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of March 31, 2022
			(in millions)			
AEP (a)(b)(c)(d)(e)	$ 2,741.7	$ 25.8	$ 37.2	$ (4.9)	$ 16.6	$ 2,816.4
PSO (a)(d)	57.6	0.9	12.8	—	—	71.3
SWEPCo (a)(c)(d)	222.7	2.4	15.4	(4.1)	13.4	249.8

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.94 billion and $1.93 billion as of March 31, 2022 and December 31, 2021, respectively.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) Includes $19 million and $18 million as of March 31, 2022 and December 31, 2021, respectively, of ARO classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended March 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	$ 1,150.8	$ 600.6	$ —	$ —	$ —	$ —	$ 1,751.4
Commercial Revenues	572.9	289.7	—	—	—	—	862.6
Industrial Revenues	563.0	133.3	—	—	—	(0.4)	695.9
Other Retail Revenues	47.4	11.6	—	—	—	—	59.0
Total Retail Revenues	2,334.1	1,035.2	—	—	—	(0.4)	3,368.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues	187.2	—	—	40.3	—	—	227.5
Transmission Revenues (a)	105.3	154.9	414.5	—	—	(361.8)	312.9
Renewable Generation Revenues (b)	—	—	—	22.4	—	(0.8)	21.6
Retail, Trading and Marketing Revenues (c)	—	—	—	388.8	3.2	(9.0)	383.0
Total Wholesale and Competitive Retail Revenues	292.5	154.9	414.5	451.5	3.2	(371.6)	945.0
Other Revenues from Contracts with Customers (b)	61.6	53.8	(0.2)	8.6	13.9	(18.6)	119.1
Total Revenues from Contracts with Customers	2,688.2	1,243.9	414.3	460.1	17.1	(390.6)	4,433.0
Other Revenues:							
Alternative Revenues (b)	(0.8)	(3.4)	(2.9)	—	—	1.3	(5.8)
Other Revenues (b) (d)	—	6.3	—	159.2	2.8	(2.9)	165.4
Total Other Revenues	(0.8)	2.9	(2.9)	159.2	2.8	(1.6)	159.6
Total Revenues	$ 2,687.4	$ 1,246.8	$ 411.4	$ 619.3	$ 19.9	$ (392.2)	$ 4,592.6

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $327 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 $9 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Three Months Ended March 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	$ 1,046.1	$ 548.1	$ —	$ —	$ —	$ —	$ 1,594.2
Commercial Revenues	486.2	239.2	—	—	—	—	725.4
Industrial Revenues	484.0	85.7	—	—	—	(0.2)	569.5
Other Retail Revenues	37.8	10.0	—	—	—	—	47.8
Total Retail Revenues	2,054.1	883.0	—	—	—	(0.2)	2,936.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues	352.6	—	—	40.5	—	—	393.1
Transmission Revenues (a)	89.0	130.5	360.4	—	—	(299.3)	280.6
Renewable Generation Revenues (b)	—	—	—	22.4	—	(0.7)	21.7
Retail, Trading and Marketing Revenues (c)	—	—	—	569.8	1.2	(31.8)	539.2
Total Wholesale and Competitive Retail Revenues	441.6	130.5	360.4	632.7	1.2	(331.8)	1,234.6
Other Revenues from Contracts with Customers (b)	42.3	52.1	4.6	1.5	8.6	(21.2)	87.9
Total Revenues from Contracts with Customers	2,538.0	1,065.6	365.0	634.2	9.8	(353.2)	4,259.4
Other Revenues:							
Alternative Revenues (b)	(0.7)	17.2	12.0	—	—	(11.6)	16.9
Other Revenues (b)	—	5.3	—	—	3.1	(3.6)	4.8
Total Other Revenues	(0.7)	22.5	12.0	—	3.1	(15.2)	21.7
Total Revenues	$ 2,537.3	$ 1,088.1	$ 377.0	$ 634.2	$ 12.9	$ (368.4)	$ 4,281.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $273 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 $32 million. The remaining affiliated amounts were immaterial.

	Three Months Ended March 31, 2022						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 141.9	$ —	$ 458.0	$ 231.8	$ 458.7	$ 165.9	$ 175.9
Commercial Revenues	94.9	—	153.9	126.6	194.7	97.5	130.5
Industrial Revenues	30.6	—	153.8	136.5	102.7	78.6	84.7
Other Retail Revenues	8.2	—	20.6	1.3	3.3	21.2	2.4
tal Retail Revenues	275.6	—	786.3	496.2	759.4	363.2	393.5
ıolesale Revenues:							
Generation Revenues (a)	—	—	56.2	90.4	—	9.5	61.2
Transmission Revenues (b)	133.1	400.3	41.1	8.8	21.8	9.6	35.2
tal Wholesale Revenues	133.1	400.3	97.3	99.2	21.8	19.1	96.4
Other Revenues from Contracts with Customers (c)	9.3	(0.3)	24.3	29.9	44.6	5.4	5.3
Total Revenues from Contracts with Customers	418.0	400.0	907.9	625.3	825.8	387.7	495.2
her Revenues:							
Alternative Revenues (d)	(1.3)	0.4	(0.7)	—	(2.1)	(0.1)	(0.4)
Other Revenues (d)	—	—	0.1	(0.1)	6.3	—	—
tal Other Revenues	(1.3)	0.4	(0.6)	(0.1)	4.2	(0.1)	(0.4)
tal Revenues	$ 416.7	$ 400.4	$ 907.3	$ 625.2	$ 830.0	$ 387.6	$ 494.8

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $36 million primarily related to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $323 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $10 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended March 31, 2021						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 122.7	$ —	$ 416.9	$ 213.6	$ 425.3	$ 136.8	$ 166.3
Commercial Revenues	80.7	—	130.2	113.6	158.5	72.7	112.9
Industrial Revenues	26.5	—	130.9	128.4	59.2	56.4	70.6
Other Retail Revenues	6.8	—	16.9	1.4	3.2	15.7	2.3
tal Retail Revenues	236.7	—	694.9	457.0	646.2	281.6	352.1
holesale Revenues:							
Generation Revenues (a)	—	—	72.4	79.6	—	(7.1)	228.6
Transmission Revenues (b)	112.0	345.2	34.2	8.3	18.5	9.4	28.9
tal Wholesale Revenues	112.0	345.2	106.6	87.9	18.5	2.3	257.5
Other Revenues from Contracts with Customers (c)	16.2	4.6	13.1	20.7	36.0	12.6	6.4
Total Revenues from Contracts with Customers	364.9	349.8	814.6	565.6	700.7	296.5	616.0
ther Revenues:							
Alternative Revenues (d)	(0.7)	11.9	2.2	(1.1)	17.9	(0.4)	0.1
Other Revenues (d)	—	—	0.2	—	5.3	—	—
tal Other Revenues	(0.7)	11.9	2.4	(1.1)	23.2	(0.4)	0.1
tal Revenues	$ 364.2	$ 361.7	$ 817.0	$ 564.5	$ 723.9	$ 296.1	$ 616.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $32 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $270 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $16 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of March 31, 2022. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2022	2023-2024	2025-2026	After 2026	Total
			(in millions)		
AEP	$ 926.3	$ 164.7	$ 157.8	$ 102.1	$ 1,350.9
AEP Texas	410.0	—	—	—	410.0
AEPTCo	1,104.2	—	—	—	1,104.2
APCo	147.8	32.2	24.3	11.6	215.9
I&M	24.9	8.8	8.8	4.5	47.0
OPCo	55.4	—	—	—	55.4
PSO	8.4	—	—	—	8.4
SWEPCo	31.5	—	—	—	31.5

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 material contract assets as of March 31, 2022 and December 31, 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 sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of March 31, 2022 and December 31, 2021.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrant Subsidiaries' balance sheets within the Accounts Receivable - Customers line item. The Registrant Subsidiaries' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of March 31, 2022 and December 31, 2021. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Company	March 31, 2022	December 31, 2021
	(in millions)	
AEP Texas	$ 0.7	$ 0.4
AEPTCo	110.5	95.5
APCo	60.9	117.8
I&M	37.3	61.2
OPCo	53.6	51.7
PSO	13.9	18.8
SWEPCo	19.5	24.7

CONTROLS AND PROCEDURES

During the first quarter of 2022, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of March 31, 2022, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of 2022 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2021 includes a detailed discussion of risk factors.As of March 31, 2022, the risk factors appearing in AEP’s 2021 Annual Report are supplemented and updated as follows:

Supply chain disruptions and inflation could negatively impact operations and corporate strategy. (Applies to all Registrants)

AEP’s operations and business plans depend on the global supply chain to procure the equipment, materials and other resources necessary to build and provide services in a safe and reliable manner. The delivery of components, materials, equipment and other resources that are critical to AEP’s business operations and corporate strategy has been restricted by the current domestic and global supply chain upheaval. This has resulted in the shortage of critical items. International tensions, including the ramifications of regional conflict, could further exacerbate the global supply chain upheaval. These disruptions and shortages could adversely impact business operations and corporate strategy. The constraints in the supply chain could restrict the availability and delay the construction, maintenance or repair of items that are needed to support normal operations or are required to execute AEP’s corporate strategy for continued capital investment in utility equipment. These disruptions and constraints could reduce future net income and cash flows and possibly harm AEP’s financial condition.

Supply chain disruptions have contributed to higher prices of components, materials, equipment and other needed commodities and these inflationary increases may continue in the future. While inflation in the United States has been relatively low in recent years, during 2021, the economy in the United States encountered a material level of inflation. The impact of COVID-19 continues to increase uncertainty in the outlook of near-term economic activity, including whether inflation will continue and at what rate. AEP typically recovers increases in capital expenses from customers through rates in regulated jurisdictions. Failure to recover increased capital costs could reduce future net income and cash flows and possibly harm AEP’s financial condition. Increases in inflation raises costs for labor, materials and services, and failure to secure these on reasonable terms may adversely impact AEP’s financial condition.

Physical attacks or hostile cyber intrusions could severely impair operations, lead to the disclosure of confidential information and damage AEP’s reputation. (Applies to all Registrants)

AEP and its regulated utility businesses face physical security and cybersecurity risks as the owner-operators of generation, transmission and/or distribution facilities and as participants in commodities trading. AEP and its regulated utility businesses own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run these facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or AEP operations could view these computer systems, software or networks as targets for cyber-attack. The Federal government has notified the owners and operators of critical infrastructure, such as AEP, that the conflict between Russia and Ukraine has increased the likelihood of a cyber-attack on such systems. In addition, the electric utility business requires the collection of sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A security breach of AEP or its regulated utility businesses' physical assets or information systems, interconnected entities in RTOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system. AEP and its regulated utility businesses could be subject to financial harm associated with ransomware theft or inappropriate release of certain types of information, including sensitive customer, vendor, employee, trading or other confidential data. A successful cyber-attack on the systems that control generation, transmission, distribution or other assets could severely disrupt business operations, preventing service to customers or collection of revenues. The breach of certain business systems could affect the ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to AEP's reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. AEP and its third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their technology systems and confidential data or to attempts to disrupt utility and related business operations. While there have been immaterial incidents of phishing, unauthorized access to technology systems, financial fraud, and disruption of remote access across the AEP System, there has been no material impact on business or operations from these attacks. However, the AEP cannot guarantee that security efforts will detect or prevent breaches, operational incidents, or other breakdowns of technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations.The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act.Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended March 31, 2022.

Item 5. Other Information

None.

Item 6. Exhibits

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
4(a)	April 7, 2022 Amendment and extension to $4,000,000,000 Credit Agreement dated March 31, 2021 among the Company, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent	X							
4(b)	April 7, 2022 Amendment and extension to $1,000,000,000 Credit Agreement dated March 31, 2021 among the Company, Initial Lenders and Wells Fargo Bank National Association as Administrative Agent	X							
4(c)	April 19, 2022 Amendment and extension to $500,000,000 Credit Agreement dated January 19, 2021 among the Company, Initial Lenders and Sumitomo Mitsui Banking Corporation as Administrative Agent							X	
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
95	Mine Safety Disclosures								X
101.INS	XBRL Instance Document	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.							
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.							

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TEXAS INC.
AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: April 28, 2022