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May 23, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificates of Public Convenience (i) to Begin to Offer, Render, Furnish and/or Supply Transmission Service in the Commonwealth of Pennsylvania; (ii) to Construct and Operate an Electric Substation Facility in York County, Pennsylvania; and (iii) for any Other Approvals Necessary, Docket No: A-2024-_______

Dear Secretary Chiavetta:

Enclosed for filing please find the Application of Transource Pennsylvania, LLC ("Transource PA") for a Certificate of Public Convenience to begin to offer, render, furnish and/or supply transmission service in the Commonwealth of Pennsylvania. Filings related to this Application are also being made by Transource PA at a G-Docket (Affiliated Interest Agreements) and a P-Docket (Petition for Confirmation of Zoning Exemption). Transource PA is requesting in each of these filings that the Pennsylvania Public Utility Commission ("Commission") consolidate these three interrelated matters for disposition.

This filing includes commercially valuable and sensitive information for which Transource PA requests confidential treatment. Accordingly, a version of the Application filing marked "Public Version" has been provided for inclusion in the public record. **Transource PA respectfully requests that the Confidential Materials in its Application be maintained by the Pennsylvania Public Utility Commission under seal.**

Please note that Transource PA is filing the Public Version of the Application electronically on the Commission's website and the Application's Confidential Materials are being uploaded to the Commission's SharePoint site.

Copies of the filing are being served on the Public Advocates, the Commission's Bureau of Technical Utility Services, and affected parties in the manner indicated on the attached Certificate of Service. Please advise Transource PA if service on any other parties is required by the Commission.

Please contact the undersigned if you have any questions regarding this filing. Thank you for your attention to this matter.

Very truly yours,

John F. Povilaitis

John F. Povilaitis

JFP/ja
cc: Certificate of Service

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Transource Pennsylvania LLC for All of the Necessary Authority, Approval and Certificates of Public Convenience (i) to Begin to Offer, Render, Furnish and/or Supply Transmission Service in the Commonwealth of Pennsylvania; (ii) to construct and operate an electric substation Facility in York County, Pennsylvania; and (iii) For any Other Approvals Necessary	:	Docket No: A-2024-_______

CERTIFICATE OF SERVICE

I hereby certify that this day I served, via email or first class mail, a copy of the foregoing document upon the persons listed below in accordance with the requirements of 52 Pa. Code § 1.54.

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York County Commissioners
Attention: Julie Wheller, President Commissioner
28 East Market Street – 2nd Floor
York, PA 17401
Via First Class Mail

Jonelle Harter Eshbach, Esquire
York County Solicitor
Administrative Center
28 East Market Street
York, PA 17401
Via First Class Mail

Craig S. Sharnetzka, Esquire
Peach Bottom Township Solicitor
CGA Law Firm
135 North George Street
York, PA 17401
Via First Class Mail

Peach Bottom Township Supervisors
Attention: David E. Gemmill, Chairperson
6880 Delta Road – Suite 3
Delta, PA 17314
Via First Class Mail

Date: May 23, 2024

John F. Povilaitis

John F. Povilaitis, Esquire

PUBLIC VERSION

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Transource Pennsylvania, LLC for All of the Necessary Authority, Approvals and Certificates of Public Convenience (i) to Begin to Offer, Render, Furnish and/or Supply Transmission Service in the Commonwealth of Pennsylvania; (ii) to construct and operate an electric substation facility in York County, Pennsylvania; and (iii) for any Other Approvals Necessary	:	Docket No. A-2024-_______

APPLICATION OF TRANSOURCE PENNSYLVANIA, LLC

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

I. INTRODUCTION

1. By this Application, Transource Pennsylvania, LLC ("Transource PA" or the "Applicant") requests all necessary authority, approvals and certificates of public convenience ("CPC")[1] from the Pennsylvania Public Utility Commission ("PUC" or "Commission"), pursuant to Section 1101 (governing the issuance of certificates of public convenience for public utilities to begin to render service in territory in which they do not possess such authorization) of the Public

[1]The Commission previously granted Transource PA a CPC and approved various affiliated interest agreements in an order entered on January 23, 2018 at Commission Docket Nos. A-2017-2587821 and G-2017-2587822 in connection with Transource PA's transmission line project in Franklin and York Counties, known as the "Independence Project." However, the CPC was rescinded when the Commission denied Transource PA's separate application for the siting of the proposed Independence Project high voltage transmission line in an order entered May 24, 2021 at Docket Nos. A-2017-2640195 and A-2017-2640200. In an order dated December 6, 2023 at Docket No. 1:21-CV-01101, the United States Federal District Court for the Middle District of Pennsylvania overturned the Commission's disapproval of the siting of the Independence Project transmission line. That denial was subsequently appealed by the Commission to the U.S. Court of Appeals for the Third Circuit and that matter is currently pending. Given these events, this Application seeks approval for a new CPC. In related filings, Transource PA seeks approval of affiliated interest agreements and confirmation of its exemption from local zoning and the need for a substation control building.

Utility Code ("Code"), 66 Pa. C.S. §§1101, to commence the provision of transmission electric service in the Commonwealth of Pennsylvania. Collectively, this Application, along with the attachments contained herein, are referred to as the "Application." This Application satisfies the requirements of 52 Pa. Code §5.12 (Contents of applications). Further, this Application is part of three separate but inter-related filings being made simultaneously by Transource PA at the Commission in connection with its proposed construction, design and operation of an electric substation in Peach Bottom Township, York County, Pennsylvania, known as the "Bramah Substation." In addition to this Application, Transource PA is filing with the Commission a Petition for Confirmation of an Exemption from Local Zoning Regulation and for the Construction of Buildings in connection with the Construction of a Proposed Electric Substation in Peach Bottom Township, York County, Pennsylvania ("Petition") and an affiliated interest filing under Code Section 2102 ("Affiliated Interest Filing") for the approval of affiliated interest agreements between Transource PA and certain of its affiliates. Given the clear interrelationship among this Application, the Petition and the Affiliated Interest Filing, Transource PA requests consolidation of all three Commission filings for review, hearing if necessary, and final disposition.

2. In an Order issued February 16, 2021, the Federal Energy Regulatory Commission ("FERC") accepted a State Agreement Approach Study Agreement ("Study Agreement") between PJM Interconnection, L.L.C.[2] and the New Jersey Board of Public Utilities ("NJ BPU"), implementing the State Agreement Approach ("SAA") pursuant to PJM's Amended and Restated Operating Agreement.

3. The SAA is a supplementary transmission planning and cost allocation mechanism through which one or more state governmental entities authorized by their respective states,

[2] PJM is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. https://www.pjm.com/about-pjm.

individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state public policy requirements identified or accepted by the state or states in the PJM region.[3] The transmission expansion or enhancement is then reflected in PJM's Regional Transmission Expansion Plan ("RTEP").[4]

4. FERC accepted an executed State Agreement Approach Agreement between PJM and NJ BPU ("SAA Agreement"), intended to implement the state of New Jersey's public policy to expand the transmission system to accommodate a buildout of 7,500 megawatts ("MW") of offshore wind generation by 2035, in an Order issued April 14, 2022.[5] On October 26, 2022, the NJ BPU issued an order on the SAA proposals and selected a portfolio of fifty-two (52) transmission projects ("NJ BPU Order") to address the reliability requirements associated with the integration of offshore wind generation into the PJM system. Transource PA was competitively selected to construct a component of one of those projects, a new transmission substation in Pennsylvania. As explained further below, Transource PA has been selected by a competitive process initiated by the NJ BPU, with support from PJM under PJM's FERC-approved SAA, to construct an electric transmission substation, originally known as the North Delta Substation[6] and later changed to the "Bramah Substation," as a baseline upgrade as part of PJM's 2021 RTEP

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[3] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 142 (2013) (Compliance Order), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014) (Second Compliance Order), *order on reh'g and compliance*, 150 FERC ¶ 61,038, *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).
[4] *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61090 (2021).
[5] *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61024 (2022). Subsequently, the state of New Jersey increased its target offshore wind generation to 11,000 MW by 2040. On April 26, 2023, the NJ BPU formally requested that PJM open another competitive proposal window under the State Agreement Approach process to accommodate the State's increased public policy requirement of 11,000 MW by 2040. On February 2, 2024, PJM filed with FERC an executed State Agreement Approach Study Agreement to implement New Jersey's proposed increased offshore wind requirement. *PJM Interconnection L.L.C.*, Docket No. ER24-1187-000.
[6] References to a Pennsylvania "North Delta Substation" by the NJ BPU and PJM in various North Delta Project documents should be considered references to the "Bramah Substation" due to a change in the Substation's name.

process.[7] Further, the Bramah Substation's scope has recently been expanded by PJM, re-emphasizing the importance of and the public need for the Bramah Substation, including to PJM, the region, customers and all other key stakeholders.

5. The Bramah Substation is part of a broader portfolio (noted above as a component of one of 52 transmission projects selected by the NJ BPU) of transmission projects (referred to as the "North Delta Project") selected by NJ BPU and approved through the PJM RTEP process to address reliability issues associated with the integration of new offshore wind electric generation with the PJM system, in furtherance of New Jersey's Offshore Wind Strategic Plan under PJM's SAA.

6. Transource PA is responsible only for the construction, ownership, operation and maintenance of the Bramah Substation, which will be an integral component of the electric transmission system operated by PJM as part of the broader North Delta Project.

7. The Bramah Substation will be located in York County, Peach Bottom Township, Pennsylvania on approximately 46 contiguous acres of land. The Bramah Substation is estimated to cost approximately $104.1 million based on PJM's latest enhancement of the project and has an expected in-service date of December 31, 2027. Transource PA has site control of the land on which the Bramah Substation will be located and is not seeking any right of condemnation or eminent domain authority in this Application to construct this facility.[8]

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[7] PJM's RTEP identifies transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM customers. PJM's region-wide RTEP approach integrates transmission with generation and load response projects to meet load-serving obligations. The rules and procedures for the RTEP process are set forth in schedule 6 of the PJM Operating Agreement. In accordance with those rules, PJM prepares a plan for the enhancement and expansion of transmission facilities in the PJM region. https://www.pjm.com/planning/rtep-development.

[8] As mentioned previously, this Application is limited to the work necessary to construct the substation. Transource PA is in the process of ascertaining whether and what type of additional site control, if any, may be needed to construct some of the conductor cut ins that will extend short distances from inside the Bramah Substation to the first transmission line structure outside the substation owned by the transmission line owner. *See* Footnote 21, *infra*.

8. As a prerequisite to the work necessary to construct the Bramah Substation and ultimately commence the provision of electric transmission service in the Commonwealth of Pennsylvania, Transource PA seeks Commission approval to begin to furnish and supply electric transmission service to or for the public via the new Bramah Substation to be constructed in York County, Peach Bottom Township, Pennsylvania and such other transmission-related facilities owned or operated by Transource PA. At this time, Transource PA is not seeking Commission authority to site any new transmission lines. Transource PA further seeks from the Commission all other approvals and certificates appropriate, customary or necessary under the Code to carry out the transactions contemplated in this Application in a lawful manner.

9. The complete name and address of the Applicant is:

Transource Pennsylvania, LLC
1 Riverside Plaza
Columbus, Ohio 43215-2372
Attention: David E. Rupert

10. The attorneys for the Applicant are:

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11. The Applicant's attorneys are authorized to receive all notices and communications regarding the Application.

II. THIS APPLICATION IS ORGANIZED AS FOLLOWS:

- Section III. provides a description of Transource PA, and other entities related to Transource PA;
- Section IV. provides a description of Bramah Substation, the need for the substation project and the process before the NJ PBU, PJM and the FERC that has preceded the filing of the Application;
- Section V. sets forth the legal standard applicable to the granting of a CPC by this Commission;
- Section VI. demonstrates that Transource PA satisfies all legal requirements necessary for the granting of a CPC including that the proposed transmission service will be to or for the public;
- Section VII. confirms that Transource PA will have no retail customers and that no Transource PA rates will be subject to Commission jurisdiction;
- Section VIII. requests consolidation for hearing and decision purposes of all the various requests for relief assigned to different Commission docket numbers related to the Application; and
- Section IX. sets forth the conclusion and summarizes the relief/approvals requested in the Application.

12. Transource PA submits, as explained in greater detail below, that all legal requirements necessary for granting the required approvals under the Code have been fully satisfied, and the Application should be approved without conditions.

III. THE APPLICANT AND RELATED ENTITIES

A. Applicant

13. Transource PA is a limited liability company, organized and existing under the laws of Delaware. Transource PA is a wholly owned subsidiary of Transource Energy, LLC ("Transource Energy"), a partnership between two investor-owned utilities, American Electric Power Company, Inc. ("AEP") and Evergy, Inc., formed to develop and invest in competitive electric transmission projects across the United States.

14. Transource PA was formed to construct, own, operate and maintain transmission facilities within the Commonwealth of Pennsylvania. Substations are a necessary component of electric transmission systems.

15. Upon receipt of all necessary approvals requested in this Application, Transource PA will construct, own, operate and maintain the Bramah Substation.

B. Related Entities

16. Transource Energy is a limited liability company organized and existing under the laws of Delaware. Transource Energy is headquartered in Columbus, Ohio.

17. Transource Energy is the direct parent of, and wholly owns, Transource PA.

18. Transource Energy participates in four RTOs, including PJM, the Midwest Independent System Operator, the New York Independent System Operator, and the Southwest Power Pool. Transource Energy is focused on the development and investment in competitive electric transmission projects across the United States.

19. AEP is a corporation organized and existing under the laws of New York.

20. Headquartered in Columbus, Ohio, AEP is an energy and utility holding company that, through its subsidiaries: (i) serves more than 5.5 million customers in eleven states; (ii) owns and operates more than 40,000 circuit miles of electric transmission lines, and approximately 259,000 miles of electric distribution lines; and (iii) has nearly 30,000 MW of generating capacity.

21. Evergy, headquartered in Kansas City, Missouri, was formed from the merger of Great Plains Energy Incorporated and Westar Energy, Inc. in 2018. Evergy's regulated utility units operate as Evergy Metro, Inc. (f/k/a Kansas City Power & Light Company ("KCP&L)), Evergy Missouri West, Inc. (f/k/a KCP&L Greater Missouri Operations, Inc.) and Evergy Kansas Central, Inc. (f/k/a Westar Energy, Inc.). The Evergy operating companies have served customers

in Kansas and Missouri for more than 100 years. Evergy's vertically integrated, regulated electric utilities serve approximately 1.6 million customers in Kansas and Missouri with 10,200 circuit miles of transmission lines and about 60,400 circuit miles of distribution lines. Evergy has approximately 15,400 megawatts of owned generating capacity and renewable power purchase agreements.

22. Attached as Appendix 1 is an organizational chart showing Transource Energy and its primary current subsidiaries.

IV. BRAMAH SUBSTATION PROJECT

A. Background on SAA Process

23. The Bramah Substation project is the culmination of various regulatory actions and approvals at the federal and state level that have been underway for over a decade.

24. In Order No. 1000[9], the FERC directed transmission providers to "describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the … regional transmission planning processes."[10]

25. In PJM's initial Order No. 1000 compliance filing[11], PJM included the SAA planning mechanism to provide a supplemental process for PJM to consider state public policies in its regional planning process. The SAA process was developed through the collaborative efforts of PJM, PJM stakeholders, and the Organization of PJM States, Inc. ("OPSI")[12].

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[9] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("Order No. 1000").

[10] Order No. 1000 at P 203.

[11] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Docket No. ER13-198-000, Compliance Filing of PJM Interconnection, L.L.C. (Oct. 25, 2012) ("*PJM October 2012 Compliance Filing*").

[12] OPSI is an inter-governmental organization of utility regulatory agencies of 14 jurisdictions that are wholly or partly in the PJM service area. https://opsi.us/

26. PJM's existing SAA is a means by which a state (or states) can include its public policy requirements in PJM's transmission planning parameters and voluntarily agree to develop the necessary transmission under PJM's RTEP development process to achieve these state public policy goals, regardless of whether the state-sponsored project is needed to address PJM's required planning criteria specific to reliability, operational performance or market efficiency.[13] The SAA process was designed to allow a state governmental entity (or a group thereof), authorized by their respective state(s), to submit a project that addresses public policy goals identified by such state(s).[14] Costs for transmission projects arising from the SAA process are allocated to the customers of the state utilizing the SAA process. In January 2020, the State of New Jersey formally set forth its state public policy to expand the transmission system to accommodate a buildout of 7,500 MW of offshore wind generation by 2035.[15]

27. On November 18, 2020, the NJ BPU issued an order requesting that PJM, pursuant to the SAA, open a competitive proposal window to solicit transmission proposals to interconnect and ensure deliverability of 7,500 MW of offshore wind generation by 2035.[16]

28. On February 16, 2021, the FERC entered an order ("Study Agreement Order") accepting the Study Agreement between PJM and the NJ BPU to effectuate the NJ BPU's formal request that PJM solicit transmission project proposals under the SAA to integrate New Jersey's planned offshore wind resources.[17]

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[13] *PJM October 2012 Compliance Filing* at 48.
[14] *See* PJM Operating Agreement, Schedule 6, section 1.5.9.
[15] State of New Jersey, 2019 Energy Master Plan, Pathway to 2050 (2019),https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf.
[16] *See PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178 at P 4 (citing *In the Matter of Offshore Wind Transmission*, Order, NJ BPU Docket No. QO20100630, at 7-8 (Nov. 18, 2020)).
[17] *PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,090 (2021).

29. In accordance with the FERC Study Agreement Order, PJM opened a competitive proposal window on April 15, 2021 and received transmission project proposals until the window closed on September 17, 2021.

30. On April 14, 2022, the FERC accepted Rate Schedule No. 49, which is the SAA Agreement between PJM and the NJ BPU.[18] The SAA Agreement established the process for the review and selection of specific transmission projects, which could be onshore or offshore facilities, to effectuate New Jersey's public policy goals.

31. On October 26, 2022, the NJ BPU Order was issued on the SAA proposals and it selected fifty-two (52) transmission projects.[19] Transmission system expansion and upgrades in New Jersey and Pennsylvania, including the North Delta Project, are necessary to resolve reliability issues that arise from integrating the new offshore wind generation into the existing grid.

B. Description of the North Delta Project and Bramah Substation

32. As noted above, the Bramah Substation is one component of the North Delta Project selected by the NJ BPU in the NJ BPU Order pursuant to the competitive process described above with PJM's support, that was subsequently approved by PJM's Board of Managers as a baseline upgrade as part of PJM's 2021 RTEP. In addition, Transource PA has to date executed a Designated Entity Agreement ("DEA") with PJM for the Bramah Substation and a second DEA for additional work associated with the Bramah Substation as described in Paragraph 35 below. These two DEAs, required by PJM's FERC-approved Open Access Transmission Tariff, are

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[18]*See SAA Agreement Order*, 179 FERC ¶ 61,024.
[19]*See* NJ BPU, *In The Matter Of Declaring Transmission To Support Offshore Wind A Public Policy Of The State Of New Jersey*, Docket No. QO20100630 (Oct. 26, 2022).

attached as Appendix 2.[20] Transource PA anticipates executing an additional DEA associated with the Bramah Substation. That draft DEA has not yet been finalized by PJM. When finalized and fully executed, Transource PA will file the completed agreement with the Commission.

33. As originally proposed and approved by the NJ BPU, the North Delta Project consisted of six elements, all of which are the responsibility of entities other than Transource PA except for item No. 2 below: (1) an upgrade to the existing Graceton 230 kV Substation; (2) the construction of a new greenfield Bramah Substation[21] (Transource PA responsibility); (3) the construction of a rebuilt Bramah – Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper – Graceton 230 kV line to double circuit; (4&5) the construction of facilities required to bring two existing lines, Peach Bottom – Delta Power Plant 500 kV and Cooper – Graceton 230 kV, "in and out" of the Bramah Substation; and (6) additional work on the Peach Bottom and the Conastone Substation located in Maryland, as designated by PJM. Transource PA is only responsible for the construction of the new Bramah Substation, item (2) above.

34. As originally approved by the NJ BPU with PJM's support, the Bramah Substation involved the construction and development of the 500/230 kV Bramah Substation with a 500 kV feed from the Calpine York Energy Center (owned by Calpine Energy Solutions ("Calpine")), a 500 kV line from the Bramah Substation to Peach Bottom South Substation, transformation for

[20] The DEA is entitled "Designated Entity Agreement between PJM Interconnection, L.L.C. and Transource Pennsylvania, LLC PJM RTEP Project b3737.47: New Jersey SAA-Bramah Station". Consistent with FERC Order No. 1000 and Schedule 6 of the PJM Interconnection L.L.C. Amended and Restated Operating Agreement, PJM is required to designate entities to develop and construct specified projects to expand, replace and/or reinforce the PJM transmission system. PJM has advised Transource PA that it is the "designated entity" for the Bramah Substation, which is included in the PJM RTEP.

[21] The Bramah Substation will include conductor "cut ins" that run from the dead-end structures inside the substation and span over the substation fencing to the first transmission line structure outside the substation owned by the transmission line owner. The junction at which the facilities of the substation end and the transmission line facilities begin is known as the point of interconnection or "POI". The Bramah Substation will have six (6) 500 kV conductor cut ins and one (1) 230 kV conductor cut in. The cut ins will run approximately 300 to 800 feet in length, subject to final design being completed.

the existing Cooper Substation, and the upgrading of the double-circuit 230 kV electric transmission line to the existing Graceton Substation ("Original Work Scope").

35. However, the Original Work Scope for the Bramah Substation was expanded by PJM (the "Incremental Scope") in 2023 due to the planned retirement of the Brandon Shores Generating Station in Maryland, changes to generation flow patterns and numerous reliability issues associated with the increased load in the PJM footprint, particularly in the Doubs (Allegheny Power System) and Northern Virginia (Dominion Energy) areas, further exacerbating reliability issues in the area of the proposed North Delta Project in Pennsylvania. The Incremental Scope now includes developing and constructing the 500/230 kV Bramah Substation to allow for a 230 kV and several 500 kV transmission lines to connect with the new Bramah Substation. Specifically, as in the Original Work Scope, the existing 500 kV generator tie-line from Calpine's York Energy Center will be connected with the Bramah Substation (i.e., York Energy Center – Bramah), effectively bisecting an existing transmission line that presently runs to and connects with the Peach Bottom South Substation. An existing 500 kV transmission line operated by Baltimore Gas and Electric ("BGE") in Maryland, and PECO Energy Company ("PECO") in Pennsylvania will also be connected with the Bramah Substation (i.e., High Ridge – Bramah). BGE and PECO will own and operate several 500 kV lines to be connected with the Bramah Substation (i.e., Graceton (BGE operates the line in Maryland, and PECO operates the line in Pennsylvania) – Bramah, and two Peach Bottom South Substation – Bramah lines). Another 500 kV transmission line will connect the Rock Springs Substation to the Bramah Substation through the resultant network upgrade[22], which results from bisecting Calpine's existing generator tie-line

[22] "Network Upgrades" are modifications or additions to transmission-related facilities that are integrated with and support the overall transmission system for the general benefit of all users of the transmission system. In contrast, a

that originally terminated at the Peach Bottom South Substation (i.e., Rock Springs 5014, via 5034 to Bramah). Finally, a new PECO 230 kV line will connect the Bramah Substation to the existing Cooper Substation (i.e., Cooper – Bramah). Attached as Appendix 3 are depictions of the proposed Bramah Substation in schematic and map formats.

36. All existing/incumbent entities are expected to pursue any state commission authorizations necessary to complete their portions of the Original Scope and Incremental Scope for the Bramah Substation.

37. The Incremental Scope for the Bramah Substation results in an approximate $27.8 million increase in the estimated costs of the substation project (i.e., from about $76.3 million to about $104.1 million). The Bramah Substation is a necessary component of the Original Work Scope and the Incremental Scope.

38. The Bramah Substation, including the Original Work Scope and the Incremental Scope, is considered by PJM to be an "Incremental Multi-Driver Project", and the costs associated with the facility will be assigned using PJM's Incremental Multi-Driver Project cost allocation methodology. Under PJM's Open Access Transmission Tariff and Operating Agreement, a Multi-Driver Project is "… a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives." *See, PJM Open Access Tariff, Definitions and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.*, Section 1 Definitions. An "Incremental Multi-Driver Project" is one involving "expanding or enhancing a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or

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generator tie line is a radial interconnection (i.e., connected to the transmission system through a single point of interconnection) from a generating unit to a network facility.

public policy drivers…" *See, PJM Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.*, Schedule 6, Section 1.5.10(h).

39. The new Bramah Substation will be constructed, owned, operated and maintained by Transource PA. As noted above, Transource PA will connect the conductor cut ins at the Bramah Substation's dead-end structures to the first structure outside the Bramah Substation (i.e., the Point of Interconnection ("POI")), which will be owned by the incumbent transmission line owners (i.e., PECO or Calpine), leaving all other transmission line work, including up to and including the POIs, to incumbent utilities for connecting their existing facilities to Transource PA's Bramah Substation. Transource PA will construct conductor cut-ins from the POIs of the various transmission lines to complete the physical connection of those lines with the Bramah Substation.

C. The Need for and the Public Benefits of the Bramah Substation

40. The Bramah Substation will assist with the state of New Jersey's SAA offshore wind generation policy objectives, ensure reliability and reduce congestion within the electric transmission system. The substation project was approved by PJM through its RTEP process as a baseline upgrade. A baseline upgrade is a transmission project that results from PJM's annual RTEP process, a robust and transparent planning process regulated by FERC to address regional reliability issues.

41. The need for the Bramah Substation is based not only upon the RTEP process, but as a result of the NJ BPU selecting the substation project to enable the State of New Jersey public policy goals by addressing onshore infrastructure upgrades required to interconnect and provide for the deliverability of 7,500 MW of offshore wind into New Jersey by 2035. The NJ BPU specifically sought proposals to address reliability violations identified in interconnecting offshore wind generation and awarded the Bramah Substation project to Transource PA based on

findings that the project solves various reliability violations within PJM relating to the offshore wind generation. The substation project originated from the SAA. PJM, as part of its annual RTEP update, evaluated the overall needs for the system and proposed upgrades to the planned transmission system, including the North Delta Project, and expanded the Bramah Substation project scope to meet the evolving reliability needs of the transmission system.

42. The "need" for the Bramah Substation was identified by PJM and selected by the NJ BPU as a result of the NJ BPU's desire to interconnect offshore wind generation, following the assessment of multiple competitive transmission proposals in the NJ SAA process in 2021 and finalized in 2022. In its evaluation of how to address the deliverability of significant quantities of offshore wind as established by the NJ BPU, PJM:

- Conducted a reliability analysis that considered the specific reliability violations associated with the amounts and locations of offshore wind injections into the PJM transmission system;
- Identified the Bramah Substation project as one of the best proposed solutions to remedy identified violations;
- Conducted a generation deliverability analysis to identify the reliability violations from the injection of the modeled offshore wind generation;
- Performed technical analyses to evaluate solutions proposed to assess the performance of the proposals, which included reliability, economic, constructability, financial and legal review; and
- Conducted the full complement of PJM transmission planning reliability tests on the four finalist project scenarios selected by the NJ BPU.

43. As noted above, PJM determined the anticipated retirement of the Brandon Shores Generating Facility further exacerbated reliability issues in the general area of the North Delta Project. PJM’s 2023 analysis concluded that the combined injection of New Jersey’s offshore wind generation, changes to generation flow patterns and numerous reliability issues associated with the increased load in the PJM footprint particularly in the Doubs (Allegheny Power System)

and Northern Virginia (Dominion Energy) areas, required changing the scope of the original Bramah Substation Project through additional baseline upgrades, including the interconnection of additional 500 kV lines, to ensure continued reliability for the region.

44. While the engineering and design of the Bramah Substation is not yet complete, Transource PA has identified the general governmental approvals and permits likely to be necessary to construct the Bramah Substation, in addition to the authorizations requested in this Application, subject to confirmation of the exemption from local zoning and authorization to construct the control building at the Bramah Substation as requested in the related Transource PA Petition. Among other things, it is reasonably likely that the construction will require an approved Soil Erosion and Sedimentation Control Plan from the York County Conservation District. Because the soil disturbance in Pennsylvania is anticipated to exceed one acre, it is expected that National Pollutant Discharge Elimination System ("NPDES") permits from the Pennsylvania Department of Environmental Protection ("PADEP") will be required for discharges of stormwater associated with construction activities. In the event that a PADEP Individual NPDES Permit is required, coordination with the Pennsylvania State Historic Preservation Office ("SHPO") is also anticipated. Post-construction stormwater controls will be implemented for the Bramah Substation as needed.

45. Physical impacts to streams are not anticipated in connection with the Bramah Substation construction. General Permits from PADEP will be required for any permanent and/or temporary impacts to wetlands from access roads and groundwork. A Joint Permit from the United States Army Corps of Engineers in PA may be required for any impacts to wetlands connected to naturally reproducing trout streams. Other potential permits and approvals from the U.S. Army Corps of Engineers may include the following:

- Section 404 of the Clean Water Act
- Section 402 of the Clean Water Act - (NPDES) Rules
- Section 106 of the National Historic Preservation Act
- York County Conservation District & PADEP
- PA Soil Erosion and Sediment Control Act (25 Pa. Code Chapter 102)
- PA Dam Safety and Waterway Management (25 Pa. Code Chapter 105)

46. Transource PA also plans on consulting with and seeking any necessary approvals from the following agencies:

- U.S. Fish and Wildlife Commission ("USFWS") – federally protected plant and animal species
- Pennsylvania Department of Conservation and Natural Resources ("DCNR") – state protected plants
- Pennsylvania Fish and Boat Commission ("PFBC") – state protected fish, reptiles, amphibians
- Pennsylvania Game Commission ("PGC") – state protected bats, birds, raptors

47. Upon approval of this Application, completion of the Bramah Substation and related conductor cut ins and connections to the Bramah Substation and other proposed transmission line upgrades for the impacted area, Transource PA will provide electric transmission service in Pennsylvania in support of the approved SAA and PJM RTEP processes outlined above. However, as a prerequisite, Transource PA seeks in this Application, among other things, approval via the issuance of a CPC to commence the furnishing of electric transmission service as a Pennsylvania public utility.

V. LEGAL STANDARDS APPLICABLE TO THE GRANTING OF A CPC

A. Service to or for the Public

> (1) A "public utility" is defined in Code Section 102 as follows: Any person or corporation now or hereafter owning or operating in this Commonwealth equipment or facilities for:
>
> (i) … Transmitting, distributing or furnishing … electricity … for the production of light, heat, or power to or for the public for compensation.

66 Pa. C.S. §102.

48. The Pennsylvania Supreme Court has concluded that "the public or private character of the enterprise does not depend upon the numbers of persons by whom it is used, but upon whether or not it is open to the use and service of all members of the public who may require it."[23] The Commonwealth Court found a gas company provided service "to or for the public" when it placed no restrictions upon whom it served and provided service to the extent that capacity was available on its facilities.

49. Further, the Commission has also held that FERC-regulated transmission companies are "public utilities" under Pennsylvania law if they: (1) own, maintain, or operate in the Commonwealth equipment or facilities used for the transmission of electricity, and (2) directly or indirectly serve Pennsylvania customers for compensation.[24]

50. The electric transmission service to be furnished by Transource PA will be to or for the public for compensation.

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[23] *Drexelbrook Associates v. Pa. PUC,* 418 Pa. 430, 435, 212 A.2d 237, 239 (1965) (citations omitted).

[24] See *Petition of American Transmission Systems, Incorporated for a Declaratory Order that it is not a Public Utility as Defined in 66 Pa.* C.S. *§ 102 and is not Required to Obtain a Certificate of Public Convenience under 66 Pa.* C.S. *§ 1102(A) to Own and Operate Equipment and Facilities in Pennsylvania Used Only to Furnish Interstate Electric Transmission Service Subject to the Jurisdiction of the Federal Energy Regulatory Commission,* Docket No. P-2013-2388149 (Pa. PUC Order entered Aug. 11, 2016) (*"Petition of ATSI"*).

B. Code Section 1101 Certificate of Public Convenience

51. Code Section 1101 provides that "[u]pon the application of any proposed public utility and the approval of such application by the [C]ommission evidenced by its certificate of public convenience first had and obtained, it shall be lawful for any such proposed public utility to begin to offer, render, furnish, or supply service within this Commonwealth." 66 Pa.C.S § 1101. Thus, before an entity may lawfully begin to furnish electric transmission service within the Commonwealth, it must first submit an application with the Commission requesting a certificate of public convenience.

52. Code Section 1103 sets forth the procedure to obtain CPCs. Under Code Section 1103, a CPC will be issued if the Commission "shall find and determine that the granting of such certificate is *necessary or proper* for the service, accommodation, convenience or safety of the public."[25] 66 Pa.C.S. § 1103. The Commission has interpreted this section to require the applicant to demonstrate a public need for the service and the applicant's fitness to provide the service.[26]

53. In addition to public need and the applicant's fitness, an applicant for a CPC must demonstrate that the proposed service will "affirmatively promote the service, accommodation, convenience, or safety of the public in some substantial way."[27] The "substantial public interest" standard is satisfied by a simple preponderance of the evidence of benefits, and such burden can be met by showing a likelihood or probability of public benefits that need not be quantified or

[25] The Commonwealth Court has stated that "necessity and need are corollaries" and, for purposes of high voltage transmission lines, "necessity can be established by showing an improvement in the reliability of services or lower prices." Moreover, the "necessary or proper" standard is to be read in the disjunctive. *Transource Pennsylvania, LLC v. Pa. Pub. Util. Comm'n*, 278 A.3d. 942 (Pa. Cmwlth. 2022).
[26] See *Chester Water Authority v. Pa. PUC*, 581 Pa. 640, 868 A.2d 384 (2005); Application of Newtown Artesian Water Company, 2003 Pa. PUC LEXIS 40 (July 1, 2003).
[27] *City of York v. Pa. PUC,* 449 Pa. 136, 151, 295 A.2d 825, 828 (1972).

guaranteed.[28] Further, the substantial public benefit test does not require that every customer receive a benefit.[29]

54. As explained in Section VI.B. below, the electric transmission service to be furnished by Transource PA is reasonably necessary for the accommodation or convenience of the public.

55. Demonstrating the applicant's "fitness" involves three factors: (i) the technical capacity to meet the need in a satisfactory fashion; (ii) the financial ability to provide reliable and responsible service to the public; and (iii) legal fitness -- the ability to operate safely and legally.[30]

56. As explained in Section VI.C. below, Transource PA is technically, financially, and legally fit to provide electric transmission service in the Commonwealth of Pennsylvania.

VI. TRANSOURCE PA SATISFIES ALL LEGAL REQUIREMENTS FOR THE GRANT OF A CPC

A. Transource PA Will Provide Service to or for the Public

57. As explained above, upon receipt of all necessary approvals and the completion of the Bramah Substation and the previously described conductor cut ins and connections, Transource PA will own, operate and maintain an electric transmission substation that will transmit high voltage electricity to various Pennsylvania electric transmission substations and to the Peach Bottom generating facility, all in support of the SAA and RTEP processes described above.

58. The Bramah Substation will be part of the interconnected wholesale electric grid that provides electric service to customers throughout the PJM 13-state footprint. The

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[28] *Popowsky v. Pa. PUC,* 594 Pa. 583,611, 937 A.2d 1040, 1057 (2007).
[29] *Popowsky,* at 617-18, 937 A.2d at 1061.
[30] See *Warminster Twp. Mun. Auth. v. Pa. P.U.C.,* 138 A.2d 240 (Pa. Super. 1958).

Bramah Substation, located in Pennsylvania, will be interconnected with existing and newly upgraded or constructed electric transmission facilities in Pennsylvania that will benefit customers in the region of the North Delta Project, including customers in Pennsylvania.

59. The Pennsylvania General Assembly has specifically directed the Commission to work with the Federal Government, interstate power pools such as PJM and other states in the region to ensure adequate, safe and reliable electric service to the citizens and businesses of the Commonwealth:

> The commission, Pennsylvania electric utilities and all electricity suppliers shall work with the Federal Government, other states in the region, the North American Electric Reliability Council and its regional coordinating councils or their successors, interstate power pools, and with the independent system operator or its functional equivalent to ensure the continued provision of adequate, safe and reliable electric service to the citizens and businesses of this Commonwealth.

66 Pa.C.S. § 2805(a).

60. As a PJM Transmission Owner, Transource PA will be required by federal law to provide open access to its facilities.[31] Thus, Transource PA will hold itself out and may be required to directly serve interconnection transmission customers, electric generators, independent power producers, and suppliers through the facilities and equipment to be located within Pennsylvania.

[31] FERC Order Nos. 888 and 889 require all public utilities owning and/or controlling transmission facilities to offer non-discriminatory open access transmission service. *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. P 31,036, 61 Fed. Reg. 21,540 (1996), clarified, 76 F.E.R.C. 61,009 and 76 F.E.R.C. 61,347 (1996), *on reh'g,* Order No. 888-A, FERC Stats. and Regs. P 31,048, 62 Fed. Reg. 12,274, *clarified,* 79 F.E.R.C. 61,182 (1997), *on reh'g,* Order No. 888-B, 81 F.E.R.C. 61,248, 62 Fed. Reg. 64,688 (1997), *on reh'g,* Order No. 888-C, 82F.E.R.C. 61,046 (1998); *Open Access Same-Time Information System and Standards of Conduct,* Order No. 889, FERC Stats. & Regs. P 31,035, 61 Fed. Reg. 21,737 (1996), *on reh'g,* Order No. 889-A, FERC Stats. & Regs. P 31,049, 62 Fed. Reg. 12,484 (1997), *on reh'g,* Order No. 889-B, 81 F.E.R.C. 61,253 (1997).

61. Under these facts, Transource PA submits that it will provide electric transmission service to or for the public for compensation.

B. The Proposed Electric Transmission Service to be Furnished by Transource PA is Reasonably Necessary for the Accommodation or Convenience of the Public.

62. As described above, the Bramah Substation project (i) was borne out of the SAA and RTEP processes (both of which processes themselves have been directed and approved by FERC), (ii) has been authorized by the NJ BPU, supported and approved by the PJM Board of Directors, (iii) has been expanded to address increased needs for reliability and reduce congestion and (iv) is required to be completed in accordance PJM's Operating Agreement.

63. The Bramah Substation project, along with the larger North Delta Project of which it is a part, has been approved by FERC and PJM under the approved SAA and RTEP processes. The North Delta Project was selected by the NJ BPU to address its public policy initiatives and, as the project has been expanded, it will address both reliability and congestion issues in the transmission system.

64. The Bramah Substation will also enhance the electrical strength and reliability of the area's electric transmission grid, allow for additional and alternative paths to electricity and facilitate the interconnection of future reliability, generation, and load projects in the area as part of the area's transmission grid interconnected network.

65. There is no doubt that the Bramah Substation is reasonably necessary for the service or accommodation of the public.[32] In FERC's August 11, 2023 Order granting transmission rate incentives to Transource PA for the North Delta (a/k/a Bramah) Substation it noted that while the

[32]For example, Pennsylvania for decades has held that regional integration is a direct intrastate benefit that can support the necessity requirement for exercising eminent domain authority. See, *Stone v. Pennsylvania Utility Commission*, 162 A.2d 18 (Pa. Super 1960).

project was borne out of the SAA, which is different from the RTEP, it nevertheless is entitled to FERC's rebuttal presumption that the project will ensure reliability or reduce congestion:

> Nevertheless, we find that, based on the information provided in Transource's filing, including expert testimony and exhibits with various PJM reports, the implementation of PJM's State Agreement Approach process pursuant to the Study Agreement and PJM-NJ BPU SAA Agreement also qualifies for the rebuttable presumption as established under Order No. 679 because that process is "a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion." We find that this implementation of the PJM State Agreement Approach process pursuant to the Study Agreement and PJM-NJ BPU SAA Agreement evaluated whether the transmission projects, including Transource's Project, ensure reliability and/or reduce congestion. The implementation of PJM's State Agreement Approach process pursuant to the Study Agreement and PJM-NJ BPU SAA Agreement is open and transparent, as PJM opened a competitive proposal window to solicit transmission project proposals to address reliability and economic concerns, presented its analyses to NJ BPU and made them publicly available, provided them to the Transmission Expansion Advisory Committee, and provided opportunity for stakeholder feedback on all findings. Thus, we find that the Project selected though this implementation of the PJM State Agreement Approach process pursuant to the Study Agreement and PJM-NJ BPU SAA Agreement qualifies for the Order No. 679 rebuttable presumption.[33]

C. Transource PA is Technically, Financially and Legally Fit to Provide Electric Transmission Service in Pennsylvania

1. Technical Fitness

66. Transource PA and its parent Transource Energy will have the required managerial and technical experience to own and operate the Bramah Substation and all related equipment and facilities to render electric transmission service in Pennsylvania and beyond.

67. As explained above, Transource PA is the direct subsidiary of Transource Energy, which is indirectly owned by a partnership between AEP and Evergy. Transource Energy and Transource PA will be able to draw on the significant resources and experience of AEP's and Evergy's rigorous and proven project management practices.

[33] *Transource Pennsylvania*, LLC, Docket No. ER23-1407-001, 184 FERC ¶61,091 (issued August 11, 2023), p. 12. (Omitting internal footnotes).

68. AEP and Evergy currently employ approximately 300 people in transmission project management and construction management functions. Combined, AEP and Evergy annually manage more than $4 billion in projects and have extensive experience in transmission projects of a magnitude comparable to the Bramah Substation Project.

69. Transource Energy operates its transmission assets with the highest standards of reliability, safety, and North American Electric Reliability Corporation ("NERC")[34] compliance. Both AEP and Evergy operate multiple, fully functional control centers and employ more than 1,000 personnel in field operations to maintain, operate and restore transmission systems. Further, AEP and Evergy have developed best-in-industry skills through over a 100+ year history of siting, designing, constructing, and operating transmission grids consisting of approximately 50,000 miles of transmission lines and related substations.

70. In addition, as part of its current business practice, AEP has established partnerships with third-party engineering consultants who are trained in the appropriate application of AEP specifications and standards. Additionally, AEP has extensive experience in providing oversight to external consultants and third-party contractors, with industry-leading capabilities to effectively oversee all types of transmission and substation siting, permitting, design and construction completed by outside firms.[35]

71. By combining the unique capabilities of AEP and Evergy, Transource Energy and Transource PA will have the necessary experience and expertise to successfully

[34] On February 3, 2006, FERC certified NERC as the organization required to establish and enforce reliability standards for the bulk electric system.
[35] *Transource Pennsylvania*, LLC, Docket No. ER23-1407-001, 184 FERC ¶61,091 (issued August 11, 2023), p. 12. (Omitting internal footnotes).

construct, own, operate, and maintain the proposed Bramah Substation and related electric transmission facilities within Pennsylvania.

2. Legal Fitness

72. Transource PA is fully authorized to conduct business in the Commonwealth of Pennsylvania and is not the subject of any civil or criminal investigations or enforcement proceedings. Upon receipt of Commission approval, Transource PA will continue to be legally fit to own and operate electric transmission facilities within the Commonwealth of Pennsylvania.

73. Transource PA is a direct subsidiary of Transource Energy, which is indirectly owned by a partnership between AEP and Evergy. Transource Energy and its affiliates are in compliance in all material respects with federal and state laws in the jurisdictions in which they operate.

3. Financial Fitness

74. Transource Energy and Transource PA have the financial fitness to construct, own, maintain, and operate the Bramah Substation and all related electric transmission facilities to be constructed, owned, operated and maintained in York County, Pennsylvania.

75. Attached to this Application as Appendix 4 is Transource PA's FERC Form No. 1. Through its own financial resources, along with substantial financial support from its parent/affiliate, Transource Energy, Transource PA has the financial fitness and resources necessary to construct, own and operate the Bramah Substation and any other transmission facilities. Further, the borrowing capacity of Transource Energy through an existing credit agreement ("Transource Energy Credit Agreement") can be sized as needed, and the existing credit facility is more than sufficient to accommodate the anticipated debt financing needs for the construction of the Bramah Substation. The Transource Energy Credit Agreement is attached as

Confidential Appendix 5. The current borrowing capacity for the Transource Energy Credit Agreement is $200 million. The terms of that agreement allow for an increase in total borrowing capacity up to $300 million. This opens an additional $100 million of available credit, creates additional assurance that Transource Energy can quickly and adequately finance additional projects under the current agreement. Presently, Transource Energy has immediate access to $111 million from the existing $200 million available, along with the $100 million accordion (i.e., expansion). Additionally, Transource Energy can leverage its diversified banking relationships and manage credit facility utilization through accessing private placement capital markets and opportunistically securing long-term debt at favorable terms. This option will allow Transource Energy to ensure that the Bramah Substation project's capital needs and any future transmission service projects are met as needed. As Transource PA needs funds to support the construction, ownership and/or operation of the Bramah Substation, it will effectively incur indebtedness to Transource Energy.

76. The financial fitness of Transource PA is demonstrated by the credit rating of its direct parent, Transource Energy, whose Moody's credit rating is A2. A copy of Transource Energy's most recent Moody's credit opinion is attached as Confidential Appendix 6 .

77. The financing terms and lower debt costs available to Transource Energy as a result of its strong A2 Moody's credit rating will ultimately benefit Transource PA by reducing the cost of financing the Bramah Substation project. Moody's A2 credit rating reflects the financial strength and credit metrics of Transource Energy, and in this context evidences Transource PA's access to debt financing and its financial fitness to construct, own, operate, and maintain the Pennsylvania transmission facilities described in this Application.

78. The financial fitness of Transource PA is further evidenced by the most recent financial statements of its ultimate parent companies, AEP and Evergy. Transource PA's ultimate parents have combined available liquidity of approximately $4.3 billion, which far exceeds any equity contribution or inter-company debt amount that might be needed to support Transource PA's present and potential future transmission projects. Excerpts from AEP's and Evergy's most recent 10-Qs, including the financial statements and discussion of liquidity, are provided in Appendix 7 and Appendix 8, respectively.

79. In addition to the strong balance sheets, both ultimate parents of Transource PA have investment grade credit ratings. The most recent Moody's credit ratings reports for AEP and Evergy, as well as the past five years of credit ratings history, are attached as Confidential Appendix 9. Through Transource Energy, and consistent with the affiliate transactions contemplated in the Affiliated Interest Filing, Transource PA will have ready access to debt and equity capital as needed to fulfill its funding requirements to construct, own, operate, and maintain the Bramah Substation and any related future electric transmission facilities. AEP and Evergy have a track record of working with a significant number of banks worldwide in raising tens of billions of dollars for energy infrastructure, including over $5 billion of long-term debt financing specifically for transmission-only businesses. Transource Energy, as an affiliate of AEP and Evergy, benefits from these relationships and experience in the capital markets.

VII. RATES AND COST RECOVERY

80. The costs required to construct, place in service and operate and maintain the Transource PA transmission grid upgrades, such as the Bramah Substation, are recovered exclusively through FERC-regulated transmission wholesale rates. The costs associated with each of Transource PA's transmission grid upgrades are allocated under FERC-regulated cost allocation principles, which may vary from project to project, and are subject to modification by

FERC under federal law. Transource PA will not recover any costs or receive any revenue through retail rates because it will not have retail customers in Pennsylvania.[36]

81. As noted above, the Bramah Substation project is an Incremental Multi-Driver Project (i.e., it includes both SAA public policy and reliability drivers). The costs of these types of projects are allocated pursuant to the cost allocation methodology set forth in PJM Tariff, Schedule 12(b)(xiv)(B). The costs for the Incremental Multi-Driver Project are assigned to each driver as follows: (i) Public Policy driver (approximately 73%) and (ii) Reliability driver (approximately 27%). For the public policy (i.e., SAA) portion, the costs will be assigned to customers in New Jersey via a load-ratio share allocation. The costs for the reliability driver will be regionally allocated (50% based on load ratio share and 50% based on solution-based DFAX).[37]

82. Transource PA will have no retail customers and therefore no rates set by the Commission.

VIII. CONSOLIDATION

83. This Application seeks relief in various areas subject to the Commission's jurisdiction that are related to Transource PA's efforts to obtain a CPC for the provision of electric transmission service as a Pennsylvania public utility, along with its intention to construct, operate and maintain the Bramah Substation and related facilities. The relief requested in this Application

[36] Transource PA is currently recovering costs and receiving revenue through its FERC-regulated transmission formula rates in connection with all of its projects included in the PJM RTEP, and consistent with FERC's incentive orders for each project. See, e.g., *Transource Pennsylvania, LLC*, Docket No. ER23-1407-001, 184 FERC ¶61,091 (issued August 11, 2023). *PPL Electric Utilities Corporation PJM Interconnection, L.L.C.*, 181 FERC ¶ 61178 (2022).

[39] *See* PJM January 10, 2024 filing in FERC Docket No. ER24-843 at 7-9 and Att. A (sheet describing b3737.47). The solution-based DFAX method allocates costs in proportion to each PJM zone's use of a transmission facility as determined by each zone's DFAX value over the facility. PJM, Intra-PJM Tariffs, Sched. 12, OATT Sched. 12 (14.0.0), § (b)(iii).

is a prerequisite to the Commission's consideration of the Affiliated Interest Filing and Petition, which are both being filed simultaneously with this Application at the Commission. Indeed, the Commission could not consider the Affiliated Interest Filing and Petition without first determining and granting a CPC to Transource PA as a transmission only public utility. Therefore, regardless of having separate docket numbers that will be assigned to this Application, the Petition and the Affiliated Interest Filing, all three pleadings must be considered by the Commission in a consolidated fashion.

84. The regulations at 52 Pa. Code § 5.81 allow this Commission or the presiding officer to order the consolidation of proceedings "involving a common question of law or fact." This Application, together with the Affiliated Interest Filing and Petition, involve common issues of law and fact that, in order to further judicial economy, practicality and avoid needless duplication of litigation and resources, justify consolidation for disposition.

85. This Commission has significant discretion in deciding a Motion to Consolidate Proceedings. Consolidation of this Application, the Affiliated Interest Filing and the Petition will avoid the need for separate Administrative Law Judges, separate hearings, and duplication of witnesses, discovery, testimony and cross-examination, if needed. Moreover, consolidation of these inter-related filings into a single proceeding will avoid potentially inconsistent decisions being reached as a result of their separate treatment in different proceedings, which ultimately may require Commission resolution.

86. The consolidation of hearings, briefing (if needed) and the decision on all issues raised in this Application, the Petition and Affiliated Interest Filing will provide a common and appropriate foundation for record development, review and litigation (if necessary) of the relevant issues. Attempting to undertake multiple, separate efforts to develop and review individual

records in multiple proceedings, and to litigate (if needed) these cases based on separate records, poses substantial procedural and substantive difficulties which may be avoided if consolidation is granted.

87. In addition, consolidation of all the matters raised in this Application, the Petition and the Affiliated Interest Filing for purposes of hearing, briefing and the decision (if needed) promotes administrative efficiency. The Commission typically exercises its consolidation authority if, as in the instant case, it can avoid creating an additional, unnecessary and expensive hurdle.[38]

88. The consolidation approach requested by Transource PA for this Application, the Petition and the Affiliated Interest Filing is entirely consistent with Pennsylvania law on consolidation and is within the Commission's discretionary authority.[39]

89. For the foregoing reasons, Transource PA requests that this Commission consolidate this Application, Petition and Affiliated Interest Filing for disposition and, if necessary, before one Administrative Law Judge for hearing and recommended decision in accordance with § 5.81 of the Pennsylvania Code. 52 Pa. Code § 5.81.

IX. CONCLUSION AND SUMMARY OF REQUESTED COMMISSION APPROVAL

WHEREFORE, for all the foregoing reasons, Transource Pennsylvania, LLC respectfully requests that the Pennsylvania Public Utility Commission grant and issue all necessary and customary approvals and orders, and issue the necessary certificates of public convenience under the Public Utility Code to:

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[38] *Derek Suggs & Beverly Marell v. The Bell Telephone Company*, 1993 Pa. PUC LEXIS 86, citing *Duquesne Interruptible Complainants v. Duquesne Light Company*, P.U.C. Docket No. C-913424, (Order entered May 14, 1993); *Big Apple Dinner Theater, Inc. v. Bell of Pennsylvania*, P.U.C. Docket No. C-00934817, (Order entered on April 30, 1993).

[39] See *Pennsylvania Public Utility Commission v. Dauphin Consolidated Water Supply Co. & General Waterworks of Pa., Inc.*, 1993 Pa. PUC LEXIS 87.

1. Begin to furnish and supply electric transmission service to or for the public within the Commonwealth of Pennsylvania; and

2. Grant any and all approvals necessary to carry out the transactions contemplated by this Application.

Respectfully submitted,

____

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E-mail: hgarcia1@aep.com
Attorneys for Transource Pennsylvania, LLC

VERIFICATION

I, David E. Rupert, Vice President of Transource Pennsylvania, LLC, have read the foregoing Application and verify that the facts set forth therein are true and correct to the best of my knowledge, information and belief, and that I expect Transource Pennsylvania, LLC to be able to prove the same at any hearing hereof deemed necessary in this matter.

I understand that any false statements made herein are subject to the penalties of 18 Pa. C.S.A. § 4904, relating to unsworn falsification to authorities.

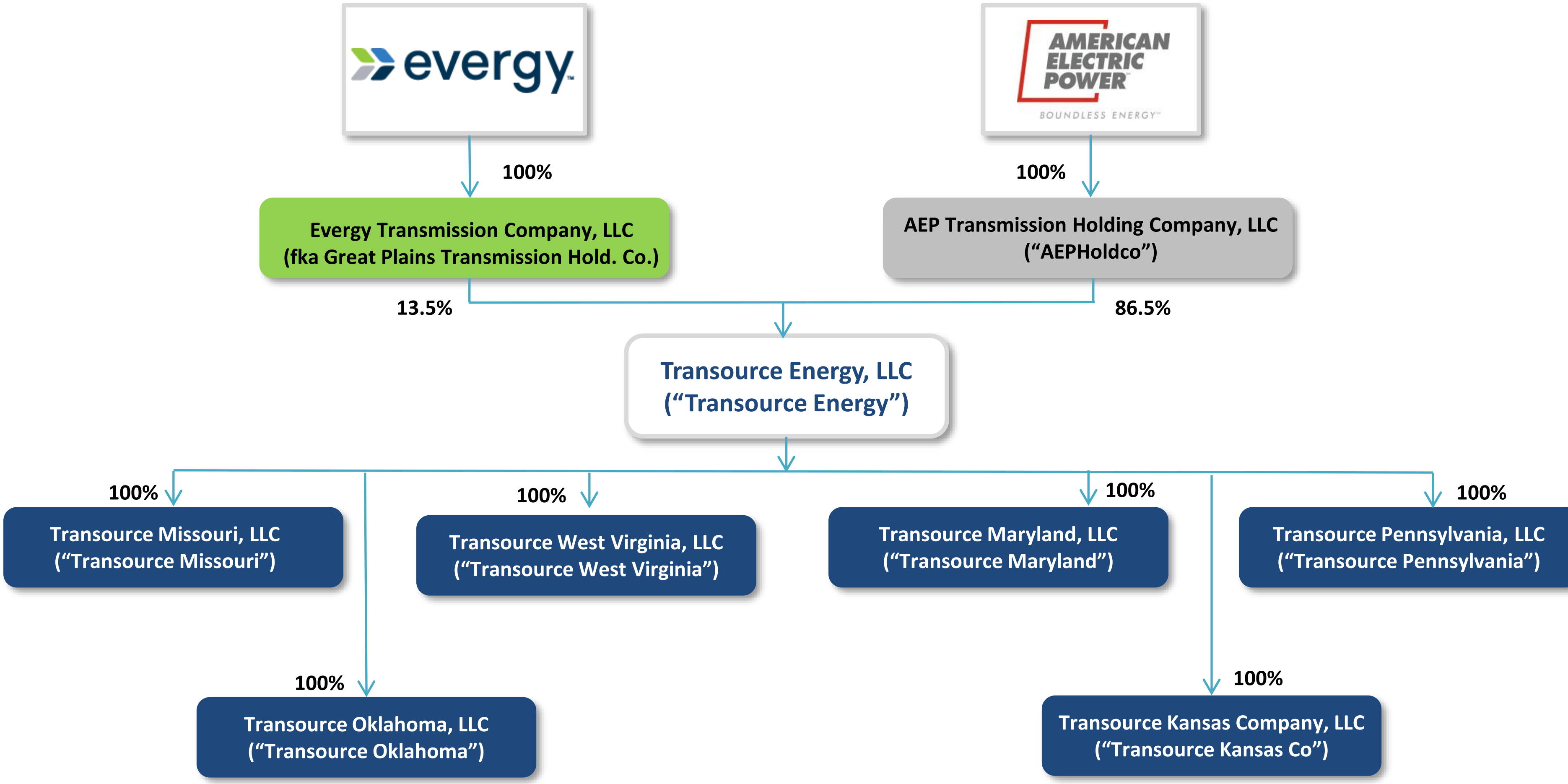
By: David E Rupert

David E. Rupert
Vice President
Transource Pennsylvania LLC

DATE: May 23, 2024

APPENDIX 1

TRANSOURCE ENERGY ORGANIZATIONAL CHART



evergy
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
100%
100%
Evergy Transmission Company, LLC
(fka Great Plains Transmission Hold. Co.)
AEP Transmission Holding Company, LLC
("AEPHoldco")
13.5%
86.5%
Transource Energy, LLC
("Transource Energy")
100%
Transource Missouri, LLC
("Transource Missouri")
100%
Transource West Virginia, LLC
("Transource West Virginia")
100%
Transource Maryland, LLC
("Transource Maryland")
100%
Transource Pennsylvania, LLC
("Transource Pennsylvania")
100%
Transource Oklahoma, LLC
("Transource Oklahoma")
100%
Transource Kansas Company, LLC
("Transource Kansas Co")

APPENDIX 2

DESIGNATED ENTITY AGREEMENT
Between
PJM Interconnection, L.L.C.
And
Transource Pennsylvania, LLC

PJM RTEP Project b3737.47:
New Jersey SAA – Bramah Station

and

DESIGNATED ENTITY AGREEMENT
Between
PJM Interconnection, L.L.C.
And
Transource Pennsylvania, LLC

PJM RTEP Projects B3800.48, B3800.49, B3800.50, AND B3800.51
PJM 2022 Window 3 Recommended Solution

DESIGNATED ENTITY AGREEMENT

Between

PJM Interconnection, L.L.C.

And

Transource Pennsylvania, LLC

PJM RTEP Project b3737.47:
New Jersey SAA – Bramah[1] Station

[1] North Delta Substation was renamed as Bramah Substation to comply with the substation naming policy of the Designated Entity.

DESIGNATED ENTITY AGREEMENT

Between

PJM Interconnection, L.L.C.

And

Transource Pennsylvania, LLC

This Designated Entity Agreement, including the Schedules attached hereto and incorporated herein (collectively, "Agreement") is made and entered into as of the Effective Date between PJM Interconnection, L.L.C. ("Transmission Provider" or "PJM"), and Transource Pennsylvania, LLC ("Designated Entity" or "Transource"), referred to herein individually as "Party" and collectively as "the Parties."

WITNESSETH

WHEREAS, in accordance with FERC Order No. 1000 and Schedule 6 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), Transmission Provider is required to designate among candidates, pursuant to a FERC-approved process, an entity to develop and construct a specified project to expand, replace and/or reinforce the Transmission System operated by Transmission Provider;

WHEREAS, pursuant to Section 1.5.8(i) of Schedule 6 of the Operating Agreement, the Transmission Provider notified Designated Entity that it was designated as the Designated Entity for the Project (described in Schedule A to this Agreement) to be included in the Regional Transmission Expansion Plan;

WHEREAS, pursuant to Section 1.5.8(j) of Schedule 6 of the Operating Agreement, Designated Entity accepted the designation as the Designated Entity for the Project and therefore has the obligation to construct the Project; and

NOW, THEREFORE, in consideration of the mutual covenants herein contained, together with other good and valuable consideration, the receipt and sufficiency is hereby mutually acknowledged by each Party, the Parties mutually covenant and agree as follows:

Article 1 – Definitions

1.0 Defined Terms.

All capitalized terms used in this Agreement shall have the meanings ascribed to them in Part I of the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in the Tariff or defined terms in this

Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

1.1 Confidential Information.

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the Project or Transmission Owner facilities to which the Project will interconnect, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, but may not be limited to, information relating to the producing party's technology, research and development, business affairs and pricing, land acquisition and vendor contracts relating to the Project.

1.2 Designated Entity Letter of Credit.

Designated Entity Letter of Credit shall mean the letter of credit provided by the Designated Entity pursuant to Section 1.5.8(j) of Schedule 6 of the Operating Agreement and Section 3.0 of this Agreement as security associated with the Project.

1.3 Development Schedule.

Development Schedule shall mean the schedule of milestones set forth in Schedule C of this Agreement.

1.4 Effective Date.

Effective Date shall mean the date this Agreement becomes effective pursuant to Section 2.0 of this Agreement.

1.5 Initial Operation.

Initial Operation shall mean the date the Project is (i) energized and (ii) under Transmission Provider operational dispatch.

1.6 Project.

Project shall mean the enhancement or expansion included in the PJM Regional Transmission Expansion Plan described in Schedule A of this Agreement.

1.7 Project Finance Entity.

Project Finance Entity shall mean holder, trustee or agent for holders, of any component of Project Financing.

1.8 Project Financing.

Project Financing shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Project, any alteration, expansion or improvement to the Project, or the operation of the Project; or (b) loans and/or debt issues secured by the Project.

1.9 Reasonable Efforts.

Reasonable Efforts shall mean such efforts as are consistent with ensuring the timely and effective design and construction of the Project in a manner, which ensures that the Project, once placed in service, meets the requirements of the Project as described in Schedule B and are consistent with Good Utility Practice.

1.10 Required Project In-Service Date.

Required Project In-Service Date shall mean the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedules B this Agreement, (ii) meet the criteria outlined in Schedule D of this Agreement and (iii) be under Transmission Provider operational dispatch.

Article 2 – Effective Date and Term

2.0 Effective Date.

Subject to regulatory acceptance, this Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is filed with FERC for acceptance, rather than reported only in PJM's Electric Quarterly Report, upon the date specified by FERC.

2.1 Term.

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Designated Entity executes the Consolidated Transmission Owners Agreement; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement, (b) meets all relevant required planning criteria, and (c) is under Transmission Provider's operational dispatch; or (iii) the Agreement is terminated pursuant to Article 8 of this Agreement.

Article 3 – Security

3.0 Obligation to Provide Security.

In accordance with Section 1.5.8(j) of Schedule 6 of the Operating Agreement, Designated Entity shall provide Transmission Provider a letter of credit as acceptable to Transmission Provider

(Designated Entity Letter of Credit) or cash security in the amount of $3,123,000, which is three percent of the estimated cost of the Project. Designated Entity is required provide and maintain the Designated Entity Letter of Credit, as required by Section 1.5.8(j) of Schedule 6 of the Operating Agreement and Section 3.0 of this Agreement. The Designated Entity Letter of Credit shall remain in full force and effect for the term of this Agreement and for the duration of the obligations arising therefrom in accordance with Article 17.0.

3.1 Distribution of Designated Entity Letter of Credit or Cash Security.

In the event that Transmission Provider draws upon the Designated Entity Letter of Credit or retains the cash security in accordance with Sections 7.5, 8.0, or 8.1, Transmission Provider shall distribute such funds as determined by FERC.

Article 4 – Project Construction

4.0 Construction of Project by Designated Entity.

Designated Entity shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule B and the Development Schedule in Schedule C; (ii) applicable reliability principles, guidelines, and standards of the Applicable Regional Reliability Council and NERC; (iii) the Operating Agreement; (iv) the PJM Manuals; and (v) Good Utility Practice.

4.1 Milestones.

4.1.0 Milestone Dates.

Designated Entity shall meet the milestone dates set forth in the Development Schedule in Schedule C of this Agreement. Milestone dates set forth in Schedule C only may be extended by Transmission Provider in writing. Failure to meet any of the milestone dates specified in Schedule C, or as extended as described in this Section 4.1.0 or Section 4.3.0 of this Agreement, shall constitute a Breach of this Agreement. Transmission Provider reasonably may extend any such milestone date, in the event of delays not caused by the Designated Entity that could not be remedied by the Designated Entity through the exercise of due diligence, or if an extension will not delay the Required Project In-Service Date specified in Schedule C of this Agreement; provided that a corporate officer of the Designated Entity submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule C of this Agreement.

4.1.1 Right to Inspect.

Upon reasonable notice, Transmission Provider shall have the right to inspect the Project for the purposes of assessing the progress of the Project and satisfaction of milestones. Such inspection shall not be deemed as review or approval by Transmission Provider of any design or construction practices or standards used by the Designated Entity.

4.2 Applicable Technical Requirements and Standards.

For the purposes of this Agreement, applicable technical requirements and standards of the Transmission Owner(s) to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project to the extent that the provisions thereof relate to the interconnection of the Project to the Transmission Owner(s) facilities.

4.3 Project Modification.

4.3.0 Project Modification Process.

The Scope of Work and Development Schedule, including the milestones therein, may be revised, as required, in accordance with Transmission Provider's project modification process set forth in the PJM Manuals, or otherwise by Transmission Provider in writing. Such modifications may include alterations as necessary and directed by Transmission Provider to meet the system condition for which the Project was included in the Regional Transmission Expansion Plan.

4.3.1 Consent of Transmission Provider to Project Modifications.

Designated Entity may not modify the Project without prior written consent of Transmission Provider, including but not limited to, modifications necessary to obtain siting approval or necessary permits, which consent shall not be unreasonably withheld, conditioned, or delayed.

4.3.2 Customer Facility Interconnections And Transmission Service Requests.

Designated Entity shall perform or permit the engineering and construction necessary to accommodate the interconnection of Customer Facilities to the Project and transmission service requests that are determined necessary for such interconnections and transmission service requests in accordance with Parts IV and VI, and Parts II and III, respectively, of the Tariff.

4.4 Project Tracking.

The Designated Entity shall provide regular, quarterly construction status reports in writing to Transmission Provider. The reports shall contain, but not be limited to, updates and information specified in the PJM Manuals regarding: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project. Transmission Provider shall use such status reports to post updates regarding the progress of the Project.

4.5 Exclusive Responsibility of Designated Entity.

Designated Entity shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with applicable laws and regulations associated with the Project, including but not limited to obtaining all necessary permits, siting, and other regulatory approvals. Transmission Provider shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 5 – Coordination with Third-Parties

5.0 Interconnection Coordination Agreement with Transmission Owner(s).

By the dates specified in the Development Schedule in Schedule C of this Agreement, Designated Entity shall execute or request to file unexecuted with the Commission: (a) an Interconnection Coordination Agreement; and (b) an interconnection agreement among and between Designated Entity, Transmission Provider, and the Transmission Owner(s) to whose facilities the Project will interconnect.

5.1 Connection with Entities Not a Party to the Consolidated Transmission Owners Agreement.

Designated Entity shall not permit any part of the Project facilities to be connected with the facilities of any entity which is not: (i) a party to Consolidated Transmission Owners Agreement without an interconnection agreement that contains provisions for the safe and reliable interconnection and operation of such interconnection in accordance with Good Utility Practice, and principles, guidelines and standards of the Applicable Regional Reliability Council and NERC or comparable requirements of an applicable retail tariff or agreement approved by appropriate regulatory authority; or (ii) a party to a separate Designated Entity Agreement.

Article 6 – Insurance

6.0 Designated Entity Insurance Requirements.

Designated Entity shall obtain and maintain in full force and effect such insurance as is consistent with Good Utility Practice. The Transmission Provider shall be included as an Additional Insured in the Designated Entity’s applicable liability insurance policies. The Designated Entity shall provide evidence of compliance with this requirement upon request by the Transmission Provider.

6.1 Subcontractor Insurance.

In accord with Good Utility Practice, Designated Entity shall require each of its subcontractors to maintain and, upon request, provide Designated Entity evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and hiring of contractors or subcontractors shall be the Designated Entity’s discretion, but regardless of bonding or the existence or non-existence of insurance, the

Designated Entity shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 7 – Breach and Default

7.0 Breach.

Except as otherwise provided in Article 10, a Breach of this Agreement shall include:

(a) The failure to comply with any term or condition of this Agreement, including but not limited to, any Breach of a representation, warranty, or covenant made in this Agreement, and failure to provide and maintain security in accordance with Section 3.0 of this Agreement;

(b) The failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule C of this Agreement, or as extended in writing as described in Sections 4.1.0 and 4.3.0 of this Agreement;

(c) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; or

(d) Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.

7.1 Notice of Breach.

In the event of a Breach, a Party not in Breach of this Agreement shall give written notice of such Breach to the breaching Party, and to any other persons, including a Project Finance Entity, if applicable, that the breaching Party identifies in writing prior to the Breach. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach.

7.2 Cure and Default.

A Party that commits a Breach and does not take steps to cure the Breach pursuant to Section 7.3 shall be in Default of this Agreement.

7.3 Cure of Breach.

The breaching Party may: (i) cure the Breach within thirty days from the receipt of the notice of Breach or other such date as determined by Transmission Provider to ensure that the Project meets its Required Project In-Service Date set forth in Schedule C; or, (ii) if the Breach cannot be cured within thirty days but may be cured in a manner that ensures that the Project meets the Required Project In-Service Date for the Project, within such thirty day time period, commences in good faith steps that are reasonable and appropriate to cure the Breach and thereafter diligently pursue such action to completion.

7.4 Re-evaluation if Breach Not Cured.

In the event that a breaching Party does not cure a Breach in accordance with Section 7.3 of this Agreement, Transmission Provider shall conduct a re-evaluation pursuant to Section 1.5.8(k) of Schedule 6 of the Operating Agreement. If based on such re-evaluation, the Project is retained in the Regional Transmission Expansion Plan and the Designated Entity's designation for the Project also is retained, the Parties shall modify this Agreement, including Schedules, as necessary. In all other events, Designated Entity shall be considered in Default of this Agreement, and this Agreement shall terminate in accordance with Section 8.1 of this Agreement.

7.5 Remedies.

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Upon Default by Designated Entity, Transmission Provider may draw upon the Designated Entity Letter of Credit. Nothing in this Section 7.5 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Designated Entity resulting from Designated Entity's Default of this Agreement.

7.6 Remedies Cumulative.

No remedy conferred by any provision of this Agreement is intended to be exclusive of any other remedy and each and every remedy shall be cumulative and shall be in addition to every other remedy given hereunder or now or hereafter existing at law or in equity or by statute or otherwise. The election of any one or more remedies shall not constitute a waiver of the right to pursue other available remedies.

7.7 Waiver.

Any waiver at any time by any Party of its rights with respect to a Breach or Default under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall not be deemed a waiver or continuing waiver with respect to any other Breach or Default or other matter.

Article 8 – Early Termination

8.0 Termination by Transmission Provider.

In the event that: (i) pursuant to Section 1.5.8(k) of Schedule 6 of the Operating Agreement, Transmission Provider determines to remove the Project from the Regional Transmission Expansion Plan and/or not to retain Designated Entity's status for the Project; (ii) Transmission Provider otherwise determines pursuant to Regional Transmission Expansion Planning Protocol in Schedule 6 of the Operating Agreement that the Project is no longer required to address the specific need for which the Project was included in the Regional Transmission Expansion Plan; or (iii) an event of force majeure, as defined in section 10.0 of this Attachment KK, or other event outside of the Designated Entity's control that, with the exercise of Reasonable Efforts, Designated Entity cannot alleviate and which prevents the Designated Entity from satisfying its obligations under this Agreement, Transmission Provider may terminate this Agreement by providing written notice of termination to Designated Entity, which shall become effective the later of sixty calendar days after the Designated Entity receives such notice or other such date the FERC establishes for the termination. In the event termination pursuant to this Section 8.0 is based on (ii) or (iii) above, Transmission Provider shall not have the right to draw upon the Designated Entity Letter of Credit or retain the cash security and shall cancel the Designated Entity Letter of Credit or return the cash security within thirty days of the termination of this Agreement.

8.1 Termination by Default.

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Sections 7.2 or 7.4 of this Agreement. Upon Default by Designated Entity, Transmission Provider may draw upon the Designated Entity Letter of Credit or retain the cash security.

8.2 Filing at FERC.

Transmission Provider shall make the appropriate filing with FERC as required to effectuate the termination of this Agreement pursuant to this Article 8.

Article 9 – Liability and Indemnity

9.0 Liability.

For the purposes of this Agreement, Transmission Provider's liability to the Designated Entity, any third-party, or any other person arising or resulting from any acts or omissions associated in any way with performance under this Agreement shall be limited in the same manner and to the same extent that Transmission Provider's liability is limited to any Transmission Customer, third-party or other person under Section 10.2 of the Tariff arising or resulting from any act or omission in any way associated with service provided under the Tariff or any Service Agreement thereunder.

9.1 Indemnity.

For the purposes of this Agreement, Designated Entity shall at all times indemnify, defend, and save Transmission Provider and its directors, managers, members, shareholders, officers and employees harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third-parties, arising out of or resulting from the Transmission Provider's acts or omissions associated with the performance of its obligations under this Agreement to the same extent and in the same manner that a Transmission Customer is required to indemnify, defend and save Transmission Provider and its directors, managers, members, shareholders, officers and employees harmless under Section 10.3 of the Tariff.

Article 10 – Force Majeure

10.0 Force Majeure.

For the purpose of this section, an event of force majeure shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightening, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which in any foregoing cases, by exercise of due diligence, it has been unable to overcome. An event of force majeure does not include: (i) a failure of performance that is due to an affected Party's own negligence or intentional wrongdoing; (ii) any removable or remedial causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

10.1 Notice.

A Party that is unable to carry out an obligation imposed on it by this Agreement due to Force Majeure shall notify the other Party in writing within a reasonable time after the occurrence of the cause relied on.

10.2 Duration of Force Majeure.

A Party shall not be responsible for any non-performance or considered in Breach or Default under this Agreement, for any deficiency or failure to perform any obligation under this Agreement to the extent that such failure or deficiency is due to Force Majeure. A Party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the Party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing Party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such Party shall resume performance and give prompt notice thereof to the other Party. In the event that Designated Entity is unable to perform any of its obligations under this Agreement because of an occurrence of Force Majeure, Transmission Provider may terminate this Agreement in accordance with Section 8.0 of this Agreement.

10.3 Breach or Default of or Force Majeure under Interconnection Coordination Agreement

If either of the following events prevents Designated Entity from performing any of its obligations under this Agreement, such event shall be considered a Force Majeure event under this Agreement and the provisions of this Article 10 shall apply: (i) a breach or default of the Interconnection Coordination Agreement associated with the Project by a party to the Interconnection Coordination Agreement other than the Designated Entity; or (ii) an event of Force Majeure under the Interconnection Coordination Agreement associated with the Project.

Article 11 – Assignment

11.0 Assignment.

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 11.0. Except for assignments described in Section 11.1 of this Agreement that may not result in the assignment of all rights, duties, and obligations under this Agreement to a Project Finance Entity, no partial assignments will be permitted. No Party may assign any of its rights or delegate any of its duties or obligations under this Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Designated Entity shall be contingent upon, prior to the effective date of the assignment: (i) the Designated Entity or assignee demonstrating to the satisfaction of Transmission Provider that the assignee has the technical competence and financial ability to comply with the requirements of this Agreement and to construct the Project consistent with the assignor's cost estimates for the Project; and (ii) the assignee is eligible to be a Designated Entity for the Project pursuant to Sections 1.5.8(a) and (f) of Schedule 6 of the Operating Agreement. Except as provided in an assignment to a Finance Project Entity to the contrary, for all assignments by any Party, the assignee must assume in a writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, the Tariff and the Operating Agreement.

11.1 Project Finance Entity Assignments

11.1.1 Assignment to Project Finance Entity

If an arrangement between the Designated Entity and a Project Finance Entity provides that the Project Finance Entity may assume any of the rights, duties and obligations of the Designated Entity under this Agreement or otherwise provides that the Project Finance Entity may cure a

Breach of this Agreement by the Designated Entity, the Project Finance Entity may be assigned this Agreement or any of the rights, duties, or obligations hereunder only upon written consent of the Transmission Provider, which consent shall not be unreasonably withheld, conditioned, or delayed. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement.

11.1.2 Assignment By Project Finance Entity

A Project Finance Entity that has been assigned this Agreement or any of the rights, duties or obligations under this Agreement or otherwise is permitted to cure a Breach of this Agreement, as described pursuant to Section 11.1.1 above, may assign this Agreement or any of the rights, duties or obligations under this Agreement to another entity not a Party to this Agreement only: (i) upon the Breach of this Agreement by the Designated Entity; and (ii) with the written consent of the Transmission Provider, which consent shall not be unreasonably withheld, conditioned, or delayed. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement alter or diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the Tariff and Operating Agreement.

Article 12 – Information Exchange

12.0 Information Access.

Subject to Applicable Laws and Regulations, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement, the Operating Agreement, and the Tariff. Such information shall include but not be limited to, information reasonably requested by Transmission Provider to prepare the Regional Transmission Expansion Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement, the Operating Agreement, and the Tariff.

12.1 Reporting of Non-Force Majeure Events.

Each Party shall notify the other Party when it becomes aware of its inability to comply with the provisions of this Agreement for a reason other than Force Majeure. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including, but not limited to, the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Section 12.1 shall not entitle the receiving Party to allege a cause of action for anticipatory Breach of this Agreement.

Article 13 – Confidentiality

13.0 Confidentiality.

For the purposes of this Agreement, information will be considered and treated as Confidential Information only if it meets the definition of Confidential Information set forth in Section 1.1 of this Agreement and is clearly designated or marked in writing as “confidential” on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is “confidential.” Confidential Information shall be treated consistent with Section 18.17 of the Operating Agreement. A Party shall be responsible for the costs associated with affording confidential treatment to its information.

Article 14 – Regulatory Requirements

14.0 Regulatory Approvals.

Designated Entity shall seek and obtain all required government authority authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule C of this Agreement, as applicable.

Article 15 – Representations and Warranties

15.0 General.

Designated Entity hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Designated Entity during the full time this Agreement is effective:

15.0.1 Good Standing

Designated Entity is duly organized or formed, as applicable, validly existing and in good standing under the laws of its State of organization or formation, and is in good standing under the laws of the respective State(s) in which it is incorporated.

15.0.2 Authority

Designated Entity has the right, power and authority to enter into this Agreement, to become a Party thereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of Designated Entity, enforceable against Designated Entity in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors’ rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.0.3 No Conflict.

The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of Designated Entity, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon Designated Entity or any of its assets.

Article 16 – Operation of Project

16.0 Initial Operation.

The following requirements shall be satisfied prior to Initial Operation of the Project:

16.0.1 Execution of the Consolidated Transmission Owners Agreement

Designated Entity has executed the Consolidated Transmission Owners Agreement and is able to meet all requirements therein.

16.0.2 Execution of an Interconnection Agreement

Designated Entity has executed an Interconnection Agreement with the Transmission Owner(s) to whose facilities the Project will interconnect, or such agreement has been filed unexecuted with the Commission.

16.0.3 Operational Requirements

The Project must meet all applicable operational requirements described in the PJM Manuals.

16.0.4 Parallel Operation

Designated Entity shall have all necessary systems and personnel in place to allow for parallel operation of its facilities with the facilities of the Transmission Owner(s) to which the Project is interconnected consistent with the Interconnection Coordination Agreement associated with the Project.

16.0.5 Synchronization

Designated Entity shall have received any necessary authorization from Transmission Provider and the Transmission Owner(s) to whose facilities the Project will interconnect to synchronize with the Transmission System or to energize, as applicable, per the determination of Transmission Provider, the Project.

16.1 Partial Operation.

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule C of this Agreement, provided that: (i) Designated Entity has notified Transmission Provider of the successful completion of the Project phase; (ii) Transmission Provider has determined that partial operation of the Project will not negatively impact the reliability of the Transmission System; (iii) Designated Entity has demonstrated that the requirements for Initial Operation set forth in Section 16.0 of this Agreement have been met for the Project phase; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice.

Article 17 – Survival

17.0 Survival of Rights.

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Liability and Indemnity provisions in Article 9 also shall survive termination, expiration, or cancellation of this Agreement.

Article 18 – Non-Standard Terms and Conditions

18.0 Schedule E – Addendum of Non-Standard Terms and Conditions.

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule E are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule E that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule E shall control.

Article 19 – Miscellaneous

19.0 Notices.

Any notice or request made to or by any Party regarding this Agreement shall be made by U.S. mail or reputable overnight courier to the addresses set forth below:

> Transmission Provider:
> PJM Interconnection, L.L.C.
> 2750 Monroe Blvd.
> Audubon, PA 19403
> Attention: Manager, Infrastructure Coordination
>
> Designated Entity:
> Transource Pennsylvania, LLC

1 Riverside Plaza, Columbus Ohio, 43215

Attention: Robert W. Bradish
rwbradish@aep.com

With copies to:

Hector H. Garcia-Santana
hgarcia1@aep.com

Chad A. Heitmeyer
caheitmeyer@aep.com

David E. Rupert
derupert@aep.com

19.1 No Transmission Service.

This Agreement does not entitle the Designated Entity to take Transmission Service under the Tariff.

19.2 No Rights.

Neither this Agreement nor the construction or the financing of the Project entitles Designated Entity to any rights related to Customer-Funded Upgrades set forth in Subpart C of Part VI of the Tariff.

19.3 Standard of Review.

Future modifications to this Agreement by the Parties or the FERC shall be subject to the just and reasonable standard and the Parties shall not be required to demonstrate that such modifications are required to meet the "public interest" standard of review as described in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

19.4 No Partnership.

Notwithstanding any provision of this Agreement, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit.

19.5 Headings.

The Article and Section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

19.6 Interpretation.

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

19.7 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

19.8 Further Assurances.

Each Party hereby agrees that it shall hereafter execute and deliver such further instruments, provide all information and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the terms hereof.

19.9 Counterparts.

This Agreement may be executed in multiple counterparts to be construed as one effective as of the Effective Date.

19.10 Governing Law

This Agreement shall be governed under the Federal Power Act and Delaware law, as applicable.

19.11 Incorporation of Other Documents.

The Tariff, the Operating Agreement, and the Reliability Assurance Agreement, as they may be amended from time to time, are hereby incorporated herein and made a part hereof.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

Transmission Provider: PJM Interconnection, L.L.C.

By:	Mgr., Transmission Coordination & Analysis	3/12/2024
Name	Title	Date

Printed name of signer: Augustine C. Caven

Designated Entity: Transource Pennsylvania, LLC

By: DocuSigned by: Robert Bradish CE4ED3037D3440A...	President	3/8/2024 | 7:14 PM EST
Name	Title	Date

Printed name of signer: Robert Bradish

SCHEDULE A

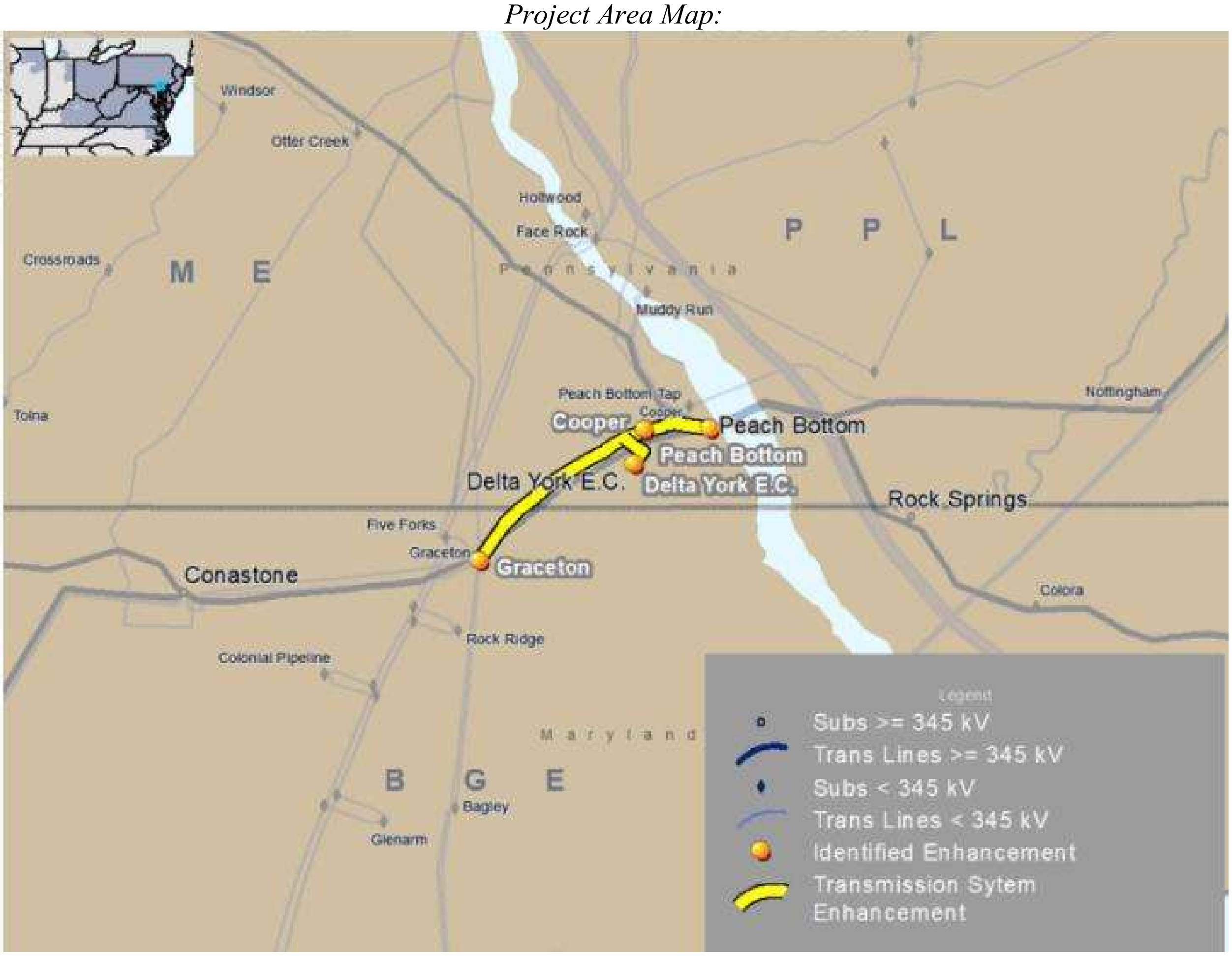
Description of Projects

Bramah[2] Substation (b3737. 47):

Build new Bramah[2] 500kV substation (four bay breaker and half configuration) – the substation will include up to 13 – 500kV breakers and one 500/230kV transformer, will allow the termination of six – 500kV lines, and one – 230kV line.

Note: Work required to tie in the station to the 500 and 230 kV lines is being covered by other PJM baseline projects.

Project Area Map:



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[2] North Delta Substation was renamed as Bramah Substation to comply with the substation naming policy of the Designated Entity.

SCHEDULE B

Scope of Work

The new Bramah[3] Substation is planned to be constructed in York County, Pennsylvania. The new Substation will be constructed with one 500/230 kV 999 MVA transformer and up to twelve breakers (in four bay, breaker and half configuration) and a breaker on the high-side of the transformer.

The new Bramah[3] Substation will tie into six 500kV transmission lines (Bramah[3]-Calpine (York Energy Center), Bramah[3]-High Ridge, Bramah[3]-Graceton, Bramah[3]-Peach Bottom South (new), Bramah[3]-Peach Bottom South (existing), and Bramah[3]-Rock Springs), and one 230kV transmission line (Bramah[3]-Cooper).

Bramah[3] Substation will include one 230kV line exit (Bramah[3]-Cooper) with space for a future 230kV ring bus to accommodate an additional transformer if needed in the future. The transmission line tie-in work to terminate all above transmission lines inside the substation will be performed by Transource.

The required transmission line work and substation remote-end work will be performed by others, and not by Transource.

The Bramah[3] Substation is designed for the following equipment:

- One at least 999 MVA 500/230 kV transformer
- Up to thirteen 500kV, 4000A, 63kA circuit breakers and one 230kV, 5000A, 63kA circuit breaker. All circuit breakers will include disconnect switches.
- Line entrance equipment for the substation, including three CCVTs and three surge arresters for each transmission line entrance to the substation.
- New Drop In Control Module (DICM) with substation relay panels, communication equipment, and DC system equipment.
- The necessary foundations, structures, and buswork to complete the 500/230kV substation layout.

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[3] North Delta Substation was renamed as Bramah Substation to comply with the substation naming policy of the Designated Entity.

SCHEDULE C

Development Schedule

Designated Entity shall ensure and demonstrate to the Transmission Provider that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

Milestones and Milestone Dates
Execute Interconnection Coordination Agreement. On or before February 28, 2026, Designated Entity must execute the Interconnection Coordination Agreement with PECO or request the agreement be filed unexecuted.
Execute Interconnection Coordination Agreement. On or before February 28, 2026, Designated Entity must execute the Interconnection Coordination Agreement with Baltimore Gas and Electric Company (BG&E) or request the agreement be filed unexecuted.
Execute Purchase/Sale Agreement. On or before June 30, 2024, Designated Entity must execute a Purchase/Sale Agreement with Calpine (York Energy Center Power Plant) or request the agreement be filed unexecuted. This agreement will address the purchase/sale of the resultant network line from the new Bramah[4] station intersection with Calpine's existing generator tie-line between Calpine's York Energy Center and PECO's Peach Bottom South substation. This agreement will also address Calpine's assignment of the cut-in work for their generator tie-line into Bramah[4], and the cut-in work associated with the resultant network line.
Demonstrate adequate Project financing. On or before December 31, 2025, Designated Entity must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement.
Acquisition of all necessary federal, state, county, and local site permits. On or before February 28, 2027, Designated Entity must demonstrate that all required federal, state, county and local site permits have been acquired.
Required Project In-Service Date. On or before December 31, 2027, Designated Entity must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules B of this Agreement; (ii) meets the criteria outlined in Schedule D of this Agreement; and (iii) is under Transmission Provider operational dispatch.

[4] North Delta Substation was renamed as Bramah Substation to comply with the substation naming policy of the Designated Entity.

SCHEDULE D

PJM Planning Requirements and Criteria and Required Ratings

Required Ratings*
Bramah[5] 500/230 kV Station:
One 500/230 kV Transformer

999SN/1248SE MVA
1248WN/1348WE MVA

* These parameters may be updated and are subject to evaluation by PJM.

[5] North Delta Substation was renamed as Bramah Substation to comply with the substation naming policy of the Designated Entity.

SCHEDULE E

Non-Standard Terms and Conditions

DESIGNATED ENTITY AGREEMENT

Between

PJM Interconnection, L.L.C.

And

Transource Pennsylvania, LLC

PJM RTEP Projects b3800.48, b3800.49, b3800.50, and b3800.51
PJM 2022 Window 3 Recommended Solution

DESIGNATED ENTITY AGREEMENT

Between

PJM Interconnection, L.L.C.

And

Transource Pennsylvania, LLC

This Designated Entity Agreement, including the Schedules attached hereto and incorporated herein (collectively, "Agreement") is made and entered into as of the Effective Date between PJM Interconnection, L.L.C. ("Transmission Provider" or "PJM"), and Transource Pennsylvania, LLC ("Designated Entity" or "Transource"), referred to herein individually as "Party" and collectively as "the Parties."

WITNESSETH

WHEREAS, in accordance with FERC Order No. 1000 and Schedule 6 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), Transmission Provider is required to designate among candidates, pursuant to a FERC-approved process, an entity to develop and construct a specified project to expand, replace and/or reinforce the Transmission System operated by Transmission Provider;

WHEREAS, pursuant to Section 1.5.8(i) of Schedule 6 of the Operating Agreement, the Transmission Provider notified Designated Entity that it was designated as the Designated Entity for the Project (described in Schedule A to this Agreement) to be included in the Regional Transmission Expansion Plan;

WHEREAS, pursuant to Section 1.5.8(j) of Schedule 6 of the Operating Agreement, Designated Entity accepted the designation as the Designated Entity for the Project and therefore has the obligation to construct the Project; and

NOW, THEREFORE, in consideration of the mutual covenants herein contained, together with other good and valuable consideration, the receipt and sufficiency is hereby mutually acknowledged by each Party, the Parties mutually covenant and agree as follows:

Article 1 – Definitions

1.0 Defined Terms.

All capitalized terms used in this Agreement shall have the meanings ascribed to them in Part I of the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in the Tariff or defined terms in this Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

1.1 Confidential Information.

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the Project or Transmission Owner facilities to which the Project will interconnect, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, but may not be limited to, information relating to the producing party's technology, research and development, business affairs and pricing, land acquisition and vendor contracts relating to the Project.

1.2 Designated Entity Letter of Credit.

Designated Entity Letter of Credit shall mean the letter of credit provided by the Designated Entity pursuant to Section 1.5.8(j) of Schedule 6 of the Operating Agreement and Section 3.0 of this Agreement as security associated with the Project.

1.3 Development Schedule.

Development Schedule shall mean the schedule of milestones set forth in Schedule C of this Agreement.

1.4 Effective Date.

Effective Date shall mean the date this Agreement becomes effective pursuant to Section 2.0 of this Agreement.

1.5 Initial Operation.

Initial Operation shall mean the date the Project is (i) energized and (ii) under Transmission Provider operational dispatch.

1.6 Project.

Project shall mean the enhancement or expansion included in the PJM Regional Transmission Expansion Plan described in Schedule A of this Agreement.

1.7 Project Finance Entity.

Project Finance Entity shall mean holder, trustee or agent for holders, of any component of Project Financing.

1.8 Project Financing.

Project Financing shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Project, any alteration, expansion or improvement to the Project, or the operation of the Project; or (b) loans and/or debt issues secured by the Project.

1.9 Reasonable Efforts.

Reasonable Efforts shall mean such efforts as are consistent with ensuring the timely and effective design and construction of the Project in a manner, which ensures that the Project, once placed in service, meets the requirements of the Project as described in Schedule B and are consistent with Good Utility Practice.

1.10 Required Project In-Service Date.

Required Project In-Service Date shall mean the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedules B this Agreement, (ii) meet the criteria outlined in Schedule D of this Agreement and (iii) be under Transmission Provider operational dispatch.

Article 2 – Effective Date and Term

2.0 Effective Date.

Subject to regulatory acceptance, this Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is filed with FERC for acceptance, rather than reported only in PJM's Electric Quarterly Report, upon the date specified by FERC.

2.1 Term.

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Designated Entity executes the Consolidated Transmission Owners Agreement; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement, (b) meets all relevant required planning criteria, and (c) is under Transmission Provider's operational dispatch; or (iii) the Agreement is terminated pursuant to Article 8 of this Agreement.

Article 3 – Security

3.0 Obligation to Provide Security.

In accordance with Section 1.5.8(j) of Schedule 6 of the Operating Agreement, Designated Entity shall provide Transmission Provider a letter of credit as acceptable to Transmission Provider (Designated Entity Letter of Credit) or cash security in the amount of $173,700, which is three percent of the estimated cost of the Project. Designated Entity is required provide and maintain the Designated Entity Letter of Credit, as required by Section 1.5.8(j) of Schedule 6 of the Operating Agreement and Section 3.0 of this Agreement. The Designated Entity Letter of Credit shall remain in full force and effect for the term of this Agreement and for the duration of the obligations arising therefrom in accordance with Article 17.0.

3.1 Distribution of Designated Entity Letter of Credit or Cash Security.

In the event that Transmission Provider draws upon the Designated Entity Letter of Credit or retains the cash security in accordance with Sections 7.5, 8.0, or 8.1, Transmission Provider shall distribute such funds as determined by FERC.

Article 4 – Project Construction

4.0 Construction of Project by Designated Entity.

Designated Entity shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule B and the Development Schedule in Schedule C; (ii) applicable reliability principles, guidelines, and standards of the Applicable Regional Reliability Council and NERC; (iii) the Operating Agreement; (iv) the PJM Manuals; and (v) Good Utility Practice.

4.1 Milestones.

4.1.0 Milestone Dates.

Designated Entity shall meet the milestone dates set forth in the Development Schedule in Schedule C of this Agreement. Milestone dates set forth in Schedule C only may be extended by Transmission Provider in writing. Failure to meet any of the milestone dates specified in Schedule C, or as extended as described in this Section 4.1.0 or Section 4.3.0 of this Agreement, shall constitute a Breach of this Agreement. Transmission Provider reasonably may extend any such milestone date, in the event of delays not caused by the Designated Entity that could not be remedied by the Designated Entity through the exercise of due diligence, or if an extension will not delay the Required Project In-Service Date specified in Schedule C of this Agreement; provided that a corporate officer of the Designated Entity submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule C of this Agreement.

4.1.1 Right to Inspect.

Upon reasonable notice, Transmission Provider shall have the right to inspect the Project for the purposes of assessing the progress of the Project and satisfaction of milestones. Such inspection shall not be deemed as review or approval by Transmission Provider of any design or construction practices or standards used by the Designated Entity.

4.2 Applicable Technical Requirements and Standards.

For the purposes of this Agreement, applicable technical requirements and standards of the Transmission Owner(s) to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project to the extent that the provisions thereof relate to the interconnection of the Project to the Transmission Owner(s) facilities.

4.3 Project Modification.

4.3.0 Project Modification Process.

The Scope of Work and Development Schedule, including the milestones therein, may be revised, as required, in accordance with Transmission Provider's project modification process set forth in the PJM Manuals, or otherwise by Transmission Provider in writing. Such modifications may include alterations as necessary and directed by Transmission Provider to meet the system condition for which the Project was included in the Regional Transmission Expansion Plan.

4.3.1 Consent of Transmission Provider to Project Modifications.

Designated Entity may not modify the Project without prior written consent of Transmission Provider, including but not limited to, modifications necessary to obtain siting approval or necessary permits, which consent shall not be unreasonably withheld, conditioned, or delayed.

4.3.2 Customer Facility Interconnections And Transmission Service Requests.

Designated Entity shall perform or permit the engineering and construction necessary to accommodate the interconnection of Customer Facilities to the Project and transmission service requests that are determined necessary for such interconnections and transmission service requests in accordance with Parts IV and VI, and Parts II and III, respectively, of the Tariff.

4.4 Project Tracking.

The Designated Entity shall provide regular, quarterly construction status reports in writing to Transmission Provider. The reports shall contain, but not be limited to, updates and information specified in the PJM Manuals regarding: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project. Transmission Provider shall use such status reports to post updates regarding the progress of the Project.

4.5 Exclusive Responsibility of Designated Entity.

Designated Entity shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with applicable laws and regulations associated with the Project, including but not limited to obtaining all necessary permits, siting, and other regulatory approvals. Transmission Provider shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 5 – Coordination with Third-Parties

5.0 Interconnection Coordination Agreement with Transmission Owner(s).

By the dates specified in the Development Schedule in Schedule C of this Agreement, Designated Entity shall execute or request to file unexecuted with the Commission: (a) an Interconnection Coordination Agreement; and (b) an interconnection agreement among and between Designated Entity, Transmission Provider, and the Transmission Owner(s) to whose facilities the Project will interconnect.

5.1 Connection with Entities Not a Party to the Consolidated Transmission Owners Agreement.

Designated Entity shall not permit any part of the Project facilities to be connected with the facilities of any entity which is not: (i) a party to Consolidated Transmission Owners Agreement without an interconnection agreement that contains provisions for the safe and reliable interconnection and operation of such interconnection in accordance with Good Utility Practice, and principles, guidelines and standards of the Applicable Regional Reliability Council and NERC or comparable requirements of an applicable retail tariff or agreement approved by appropriate regulatory authority; or (ii) a party to a separate Designated Entity Agreement.

Article 6 – Insurance

6.0 Designated Entity Insurance Requirements.

Designated Entity shall obtain and maintain in full force and effect such insurance as is consistent with Good Utility Practice. The Transmission Provider shall be included as an Additional Insured in the Designated Entity's applicable liability insurance policies. The Designated Entity shall provide evidence of compliance with this requirement upon request by the Transmission Provider.

6.1 Subcontractor Insurance.

In accord with Good Utility Practice, Designated Entity shall require each of its subcontractors to maintain and, upon request, provide Designated Entity evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and hiring of contractors or subcontractors shall be the Designated Entity's discretion, but regardless of bonding or the existence or non-existence of insurance, the Designated Entity shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 7 – Breach and Default

7.0 Breach.

Except as otherwise provided in Article 10, a Breach of this Agreement shall include:

(a) The failure to comply with any term or condition of this Agreement, including but not limited to, any Breach of a representation, warranty, or covenant made in this Agreement, and failure to provide and maintain security in accordance with Section 3.0 of this Agreement;

(b) The failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule C of this Agreement, or as extended in writing as described in Sections 4.1.0 and 4.3.0 of this Agreement;

(c) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; or

(d) Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.

7.1 Notice of Breach.

In the event of a Breach, a Party not in Breach of this Agreement shall give written notice of such Breach to the breaching Party, and to any other persons, including a Project Finance Entity, if applicable, that the breaching Party identifies in writing prior to the Breach. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach.

7.2 Cure and Default.

A Party that commits a Breach and does not take steps to cure the Breach pursuant to Section 7.3 shall be in Default of this Agreement.

7.3 Cure of Breach.

The breaching Party may: (i) cure the Breach within thirty days from the receipt of the notice of Breach or other such date as determined by Transmission Provider to ensure that the Project meets its Required Project In-Service Date set forth in Schedule C; or, (ii) if the Breach cannot be cured within thirty days but may be cured in a manner that ensures that the Project meets the Required Project In-Service Date for the Project, within such thirty day time period, commences in good faith steps that are reasonable and appropriate to cure the Breach and thereafter diligently pursue such action to completion.

7.4 Re-evaluation if Breach Not Cured.

In the event that a breaching Party does not cure a Breach in accordance with Section 7.3 of this Agreement, Transmission Provider shall conduct a re-evaluation pursuant to Section 1.5.8(k) of

Schedule 6 of the Operating Agreement. If based on such re-evaluation, the Project is retained in the Regional Transmission Expansion Plan and the Designated Entity's designation for the Project also is retained, the Parties shall modify this Agreement, including Schedules, as necessary. In all other events, Designated Entity shall be considered in Default of this Agreement, and this Agreement shall terminate in accordance with Section 8.1 of this Agreement.

7.5 Remedies.

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Upon Default by Designated Entity, Transmission Provider may draw upon the Designated Entity Letter of Credit. Nothing in this Section 7.5 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Designated Entity resulting from Designated Entity's Default of this Agreement.

7.6 Remedies Cumulative.

No remedy conferred by any provision of this Agreement is intended to be exclusive of any other remedy and each and every remedy shall be cumulative and shall be in addition to every other remedy given hereunder or now or hereafter existing at law or in equity or by statute or otherwise. The election of any one or more remedies shall not constitute a waiver of the right to pursue other available remedies.

7.7 Waiver.

Any waiver at any time by any Party of its rights with respect to a Breach or Default under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall not be deemed a waiver or continuing waiver with respect to any other Breach or Default or other matter.

Article 8 – Early Termination

8.0 Termination by Transmission Provider.

In the event that: (i) pursuant to Section 1.5.8(k) of Schedule 6 of the Operating Agreement, Transmission Provider determines to remove the Project from the Regional Transmission Expansion Plan and/or not to retain Designated Entity's status for the Project; (ii) Transmission Provider otherwise determines pursuant to Regional Transmission Expansion Planning Protocol in Schedule 6 of the Operating Agreement that the Project is no longer required to address the specific need for which the Project was included in the Regional Transmission Expansion Plan; or (iii) an event of force majeure, as defined in section 10.0 of this Attachment KK, or other event outside of the Designated Entity's control that, with the exercise of Reasonable Efforts, Designated Entity cannot alleviate and which prevents the Designated Entity from satisfying its obligations under this Agreement, Transmission Provider may terminate this Agreement by providing written notice of termination to Designated Entity, which shall become effective the later of sixty calendar days after the Designated Entity receives such notice or other such date the FERC establishes for the termination. In the event termination pursuant to this Section 8.0 is based on (ii) or (iii) above, Transmission Provider shall not have the right to draw upon the Designated Entity Letter of Credit or retain the cash security and shall cancel the Designated Entity Letter of Credit or return the cash security within thirty days of the termination of this Agreement.

8.1 Termination by Default.

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Sections 7.2 or 7.4 of this Agreement. Upon Default by Designated Entity, Transmission Provider may draw upon the Designated Entity Letter of Credit or retain the cash security.

8.2 Filing at FERC.

Transmission Provider shall make the appropriate filing with FERC as required to effectuate the termination of this Agreement pursuant to this Article 8.

Article 9 – Liability and Indemnity

9.0 Liability.

For the purposes of this Agreement, Transmission Provider's liability to the Designated Entity, any third-party, or any other person arising or resulting from any acts or omissions associated in any way with performance under this Agreement shall be limited in the same manner and to the same extent that Transmission Provider's liability is limited to any Transmission Customer, third-party or other person under Section 10.2 of the Tariff arising or resulting from any act or omission in any way associated with service provided under the Tariff or any Service Agreement thereunder.

9.1 Indemnity.

For the purposes of this Agreement, Designated Entity shall at all times indemnify, defend, and save Transmission Provider and its directors, managers, members, shareholders, officers and employees harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third-parties, arising out of or resulting from the Transmission Provider's acts or omissions associated with the performance of its obligations under this Agreement to the same extent and in the same manner that a Transmission Customer is required to indemnify, defend and save Transmission Provider and its directors, managers, members, shareholders, officers and employees harmless under Section 10.3 of the Tariff.

Article 10 – Force Majeure

10.0 Force Majeure.

For the purpose of this section, an event of force majeure shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightening, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which in any foregoing cases, by exercise of due diligence, it has been unable to overcome. An event of force majeure does not include: (i) a failure of performance that is due to an affected Party's own negligence or intentional wrongdoing; (ii) any removable or remedial causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

10.1 Notice.

A Party that is unable to carry out an obligation imposed on it by this Agreement due to Force Majeure shall notify the other Party in writing within a reasonable time after the occurrence of the cause relied on.

10.2 Duration of Force Majeure.

A Party shall not be responsible for any non-performance or considered in Breach or Default under this Agreement, for any deficiency or failure to perform any obligation under this Agreement to the extent that such failure or deficiency is due to Force Majeure. A Party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the Party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing Party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such Party shall resume performance and give prompt notice thereof to the other Party. In the event that Designated Entity is unable to perform any of its obligations under this Agreement because of an occurrence of Force Majeure, Transmission Provider may terminate this Agreement in accordance with Section 8.0 of this Agreement.

10.3 Breach or Default of or Force Majeure under Interconnection Coordination Agreement

If either of the following events prevents Designated Entity from performing any of its obligations under this Agreement, such event shall be considered a Force Majeure event under this Agreement and the provisions of this Article 10 shall apply: (i) a breach or default of the Interconnection Coordination Agreement associated with the Project by a party to the Interconnection Coordination Agreement other than the Designated Entity; or (ii) an event of Force Majeure under the Interconnection Coordination Agreement associated with the Project.

Article 11 – Assignment

11.0 Assignment.

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 11.0. Except for assignments described in Section 11.1 of this Agreement that may not result in the assignment of all rights, duties, and obligations under this Agreement to a Project Finance Entity, no partial assignments will be permitted. No Party may assign any of its rights or delegate any of its duties or obligations under this Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Designated Entity shall be contingent upon, prior to the effective date of the assignment: (i) the Designated Entity or assignee demonstrating to the satisfaction of Transmission Provider that the assignee has the technical competence and financial ability to comply with the requirements of this Agreement and to construct the Project consistent with the assignor's cost estimates for the Project; and (ii) the assignee is eligible to be a Designated Entity for the Project pursuant to Sections 1.5.8(a) and (f) of Schedule 6 of the Operating Agreement. Except as provided in an assignment to a Finance Project Entity to the contrary, for all assignments by any Party, the assignee must assume in a writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, the Tariff and the Operating Agreement.

11.1 Project Finance Entity Assignments

11.1.1 Assignment to Project Finance Entity

If an arrangement between the Designated Entity and a Project Finance Entity provides that the Project Finance Entity may assume any of the rights, duties and obligations of the Designated Entity under this Agreement or otherwise provides that the Project Finance Entity may cure a Breach of this Agreement by the Designated Entity, the Project Finance Entity may be assigned this Agreement or any of the rights, duties, or obligations hereunder only upon written consent of the Transmission Provider, which consent shall not be unreasonably withheld, conditioned, or delayed. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement.

11.1.2 Assignment By Project Finance Entity

A Project Finance Entity that has been assigned this Agreement or any of the rights, duties or obligations under this Agreement or otherwise is permitted to cure a Breach of this Agreement, as described pursuant to Section 11.1.1 above, may assign this Agreement or any of the rights, duties or obligations under this Agreement to another entity not a Party to this Agreement only: (i) upon the Breach of this Agreement by the Designated Entity; and (ii) with the written consent of the

Transmission Provider, which consent shall not be unreasonably withheld, conditioned, or delayed. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement alter or diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the Tariff and Operating Agreement.

Article 12 – Information Exchange

12.0 Information Access.

Subject to Applicable Laws and Regulations, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement, the Operating Agreement, and the Tariff. Such information shall include but not be limited to, information reasonably requested by Transmission Provider to prepare the Regional Transmission Expansion Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement, the Operating Agreement, and the Tariff.

12.1 Reporting of Non-Force Majeure Events.

Each Party shall notify the other Party when it becomes aware of its inability to comply with the provisions of this Agreement for a reason other than Force Majeure. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including, but not limited to, the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Section 12.1 shall not entitle the receiving Party to allege a cause of action for anticipatory Breach of this Agreement.

Article 13 – Confidentiality

13.0 Confidentiality.

For the purposes of this Agreement, information will be considered and treated as Confidential Information only if it meets the definition of Confidential Information set forth in Section 1.1 of this Agreement and is clearly designated or marked in writing as "confidential" on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is "confidential." Confidential Information shall be treated consistent with Section 18.17 of the Operating Agreement. A Party shall be responsible for the costs associated with affording confidential treatment to its information.

Article 14 – Regulatory Requirements

14.0 Regulatory Approvals.

Designated Entity shall seek and obtain all required government authority authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule C of this Agreement, as applicable.

Article 15 – Representations and Warranties

15.0 General.

Designated Entity hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Designated Entity during the full time this Agreement is effective:

15.0.1 Good Standing

Designated Entity is duly organized or formed, as applicable, validly existing and in good standing under the laws of its State of organization or formation, and is in good standing under the laws of the respective State(s) in which it is incorporated.

15.0.2 Authority

Designated Entity has the right, power and authority to enter into this Agreement, to become a Party thereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of Designated Entity, enforceable against Designated Entity in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.0.3 No Conflict.

The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of Designated Entity, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon Designated Entity or any of its assets.

Article 16 – Operation of Project

16.0 Initial Operation.

The following requirements shall be satisfied prior to Initial Operation of the Project:

16.0.1 Execution of the Consolidated Transmission Owners Agreement

Designated Entity has executed the Consolidated Transmission Owners Agreement and is able to meet all requirements therein.

16.0.2 Execution of an Interconnection Agreement

Designated Entity has executed an Interconnection Agreement with the Transmission Owner(s) to whose facilities the Project will interconnect, or such agreement has been filed unexecuted with the Commission.

16.0.3 Operational Requirements

The Project must meet all applicable operational requirements described in the PJM Manuals.

16.0.4 Parallel Operation

Designated Entity shall have all necessary systems and personnel in place to allow for parallel operation of its facilities with the facilities of the Transmission Owner(s) to which the Project is interconnected consistent with the Interconnection Coordination Agreement associated with the Project.

16.0.5 Synchronization

Designated Entity shall have received any necessary authorization from Transmission Provider and the Transmission Owner(s) to whose facilities the Project will interconnect to synchronize with the Transmission System or to energize, as applicable, per the determination of Transmission Provider, the Project.

16.1 Partial Operation.

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule C of this Agreement, provided that: (i) Designated Entity has notified Transmission Provider of the successful completion of the Project phase; (ii) Transmission Provider has determined that partial operation of the Project will not negatively impact the reliability of the Transmission System; (iii) Designated Entity has demonstrated that the requirements for Initial Operation set forth in Section 16.0 of this Agreement have been met for the Project phase; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice.

Article 17 – Survival

17.0 Survival of Rights.

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Liability and Indemnity provisions in Article 9 also shall survive termination, expiration, or cancellation of this Agreement.

Article 18 – Non-Standard Terms and Conditions

18.0 Schedule E – Addendum of Non-Standard Terms and Conditions.

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule E are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule E that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule E shall control.

Article 19 – Miscellaneous

19.0 Notices.

Any notice or request made to or by any Party regarding this Agreement shall be made by U.S. mail or reputable overnight courier to the addresses set forth below:

Transmission Provider:
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
Attention: Augustine Caven, Manager, Transmission Coordination and Analysis

Designated Entity:
Transource Pennsylvania, LLC
1 Riverside Plaza
Columbus Ohio, 43215

Attention: Robert W. Bradish
rwbradish@aep.com

With copies to:
Hector H. Garcia-Santana
Hgarcia1@aep.com

Chad A. Heitmeyer
caheitmeyer@aep.com

David E. Rupert
derupert@aep.com

19.1 No Transmission Service.

This Agreement does not entitle the Designated Entity to take Transmission Service under the Tariff.

19.2 No Rights.

Neither this Agreement nor the construction or the financing of the Project entitles Designated Entity to any rights related to Customer-Funded Upgrades set forth in Subpart C of Part VI of the Tariff.

19.3 Standard of Review.

Future modifications to this Agreement by the Parties or the FERC shall be subject to the just and reasonable standard and the Parties shall not be required to demonstrate that such modifications are required to meet the "public interest" standard of review as described in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

19.4 No Partnership.

Notwithstanding any provision of this Agreement, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit.

19.5 Headings.

The Article and Section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

19.6 Interpretation.

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

19.7 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

19.8 Further Assurances.

Each Party hereby agrees that it shall hereafter execute and deliver such further instruments, provide all information and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the terms hereof.

19.9 Counterparts.

This Agreement may be executed in multiple counterparts to be construed as one effective as of the Effective Date.

19.10 Governing Law

This Agreement shall be governed under the Federal Power Act and Delaware law, as applicable.

19.11 Incorporation of Other Documents.

The Tariff, the Operating Agreement, and the Reliability Assurance Agreement, as they may be amended from time to time, are hereby incorporated herein and made a part hereof.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

Transmission Provider: PJM Interconnection, L.L.C.

By:	Mgr., Transmission Coordination & Analysis	4/2/2024
Name	Title	Date

Printed name of signer: Augustine C. Caven

Designated Entity: Transource Pennsylvania, LLC

By: DocuSigned by: Robert Bradish CE4ED3037D3440A...	President	3/27/2024 | 2:48 PM EDT
Name	Title	Date

Printed name of signer: Robert W. Bradish

SCHEDULE A

Description of Project

PJM Baseline Upgrade IDs	Description of Projects
b3800.48	Bramah[1] termination for the Bramah[1]-High Ridge 500 kV line (Transource work).
b3800.49	Bramah[1] 500 kV termination for the Calpine generator (Calpine/Transource work).
b3800.50	Bramah[1] 500 kV termination for the Rock Springs 500 kV line (5034/5014 line) (Transource work).
b3800.51	Bramah[1] 500 kV termination for the new Peach Bottom-Bramah[1] 500 kV line (Transource work).

[1] North Delta Substation was renamed as Bramah Substation to comply with the substation naming convention of the Designated Entity.

SCHEDULE B

Scope of Work

The transmission line tie-in work for Bramah[2] Substation will include all necessary structures, foundations, conductor, shield wire, insulators, and hardware to connect the 500kV transmission lines into the substation. This scope applies to the following PJM projects:

- B3800.48
- B3800.49
- B3800.50
- B3800.51

The substation work for Bramah[2] Substation will be performed by Transource as described in the scope of work for PJM project b3737.47. The required transmission line work and substation remote-end work will be performed by others, and not by Transource.

In-service dates for these projects will ultimately be dependent on transmission line work and substation remote-end work performed by others.

[2] North Delta Substation was renamed as Bramah Substation to comply with the substation naming convention of the Designated Entity.

SCHEDULE C

Development Schedule

Designated Entity shall ensure and demonstrate to the Transmission Provider that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

Milestones and Milestone Dates
Execute Interconnection Coordination Agreement. On or before February 28, 2026, Designated Entity must execute the Interconnection Coordination Agreement with PECO or request the agreement be filed unexecuted.
Execute Interconnection Coordination Agreement. On or before February 28, 2026, Designated Entity must execute the Interconnection Coordination Agreement with Baltimore Gas and Electric Company (BG&E) or request the agreement be filed unexecuted.
Execute Purchase/Sale Agreement. On or before June 30, 2024, Designated Entity must execute a Purchase/Sale Agreement with Calpine (York Energy Center Power Plant) or request the agreement be filed unexecuted. This agreement will address the purchase/sale of the resultant network line from the new Bramah[3] station intersection with Calpine's existing generator tie-line between Calpine's York Energy Center and PECO's Peach Bottom South substation. This agreement will also Calpine's assignment of the cut-in work for their generator tie-line into Bramah, and the cut-in work associated with the resultant network line.
Demonstrate Adequate Project financing. On or before December 31, 2025 Designated Entity must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement.
Acquisition of all necessary federal, state, county, and local site permits. On or before February 28, 2027, Designated Entity must demonstrate that all required federal, state, county and local site permits have been acquired.
Required Project In-Service Date. On or before December 31, 2027, Designated Entity must: (i) Demonstrate that the Project is completed in accordance with the Scope of Work in Schedules B of this Agreement; (ii) meets the criteria outlined in Schedule D of this Agreement; and (iii) is under Transmission Provider operational dispatch.

[3] North Delta Substation was renamed as Bramah Substation to comply with the substation naming convention of the Designated Entity.

SCHEDULE D

PJM Planning Requirements and Criteria and Required Ratings

PJM Baseline Upgrade ID	Required Ratings (MVA): Summer Normal/Summer Emergency/Winter Normal/Winter Emergency	Planning Criteria
b3800.48	N/A	Projects that comprise 2022 RTEP Window 3 Recommended Solution collectively address the 2027/28 baseline local and regional constraints associated with Data Center load additions in APS and Dominion zones, reactive power needs, and the cumulative impact of over 11,000 MW of generation changes and deactivations. These projects all adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and local Transmission Owner FERC 715 criteria.
b3800.49	N/A	
b3800.50	N/A	
b3800.51	N/A	

SCHEDULE E

Non-Standard Terms and Conditions

(None)

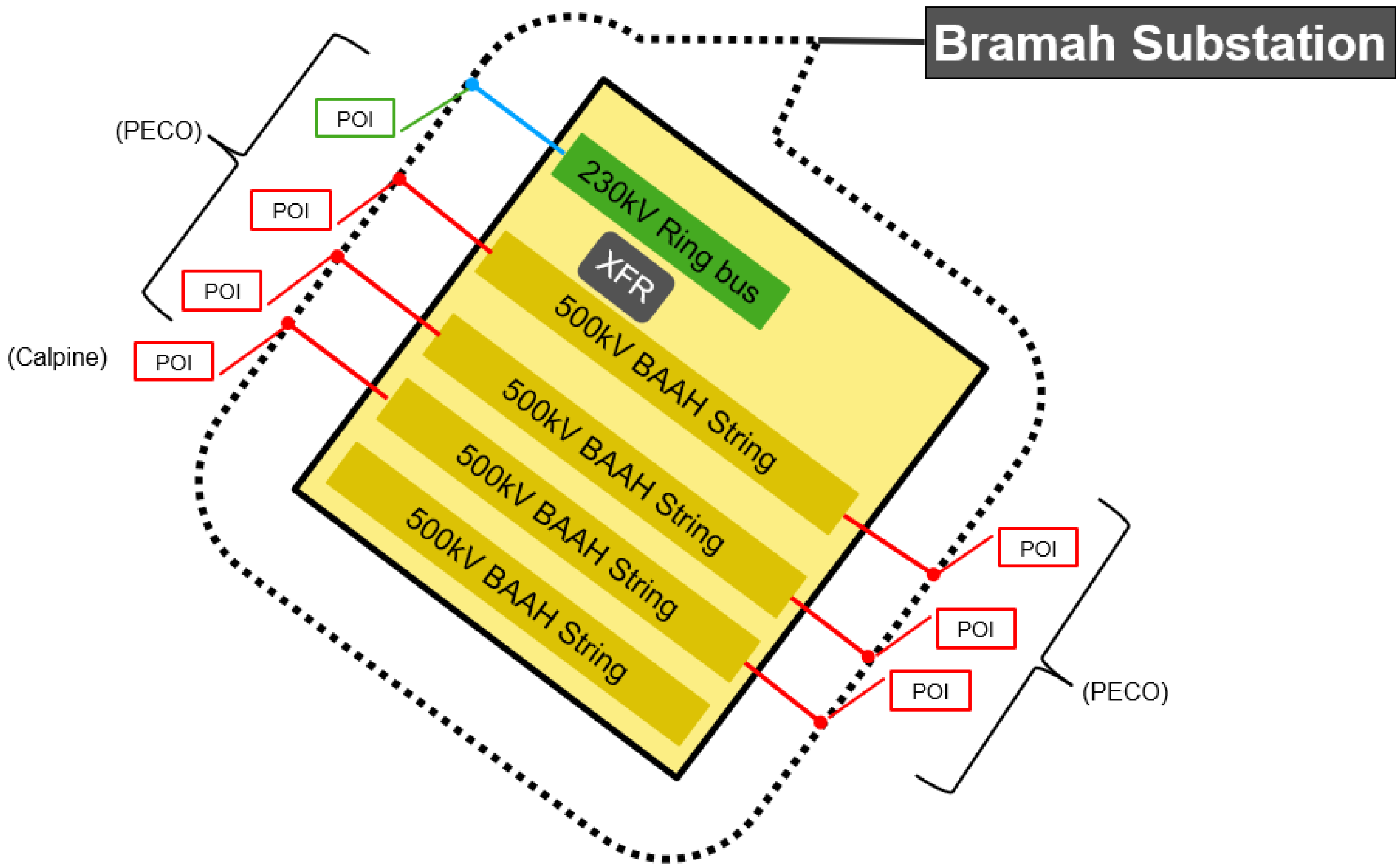
APPENDIX 3

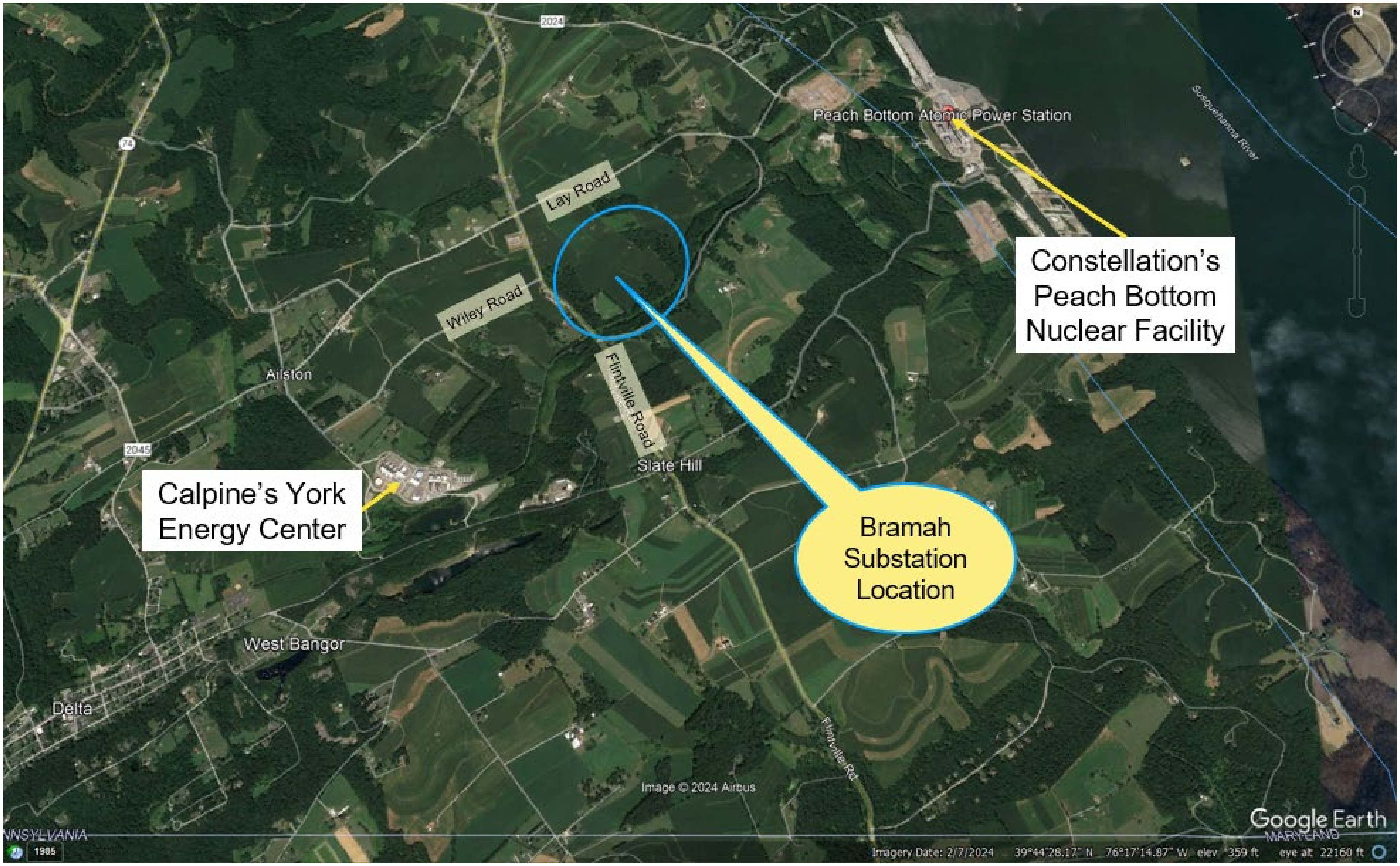
BRAMAH SUBSTATION SCHEMATIC

and

MAP OF BRAMAH SUBSTATION AREA

Appendix 3 – Bramah Substation Schematic




Peach Bottom Atomic Power Station
Constellation's
Peach Bottom
Nuclear Facility
Susquehanna River
Lay Road
Wiley Road
Flintville Road
Airston
Slate Hill
Bramah
Substation
Location
Calpine's York
Energy Center
West Bangor
Delta
Flintville Rd
Image © 2024 Airbus
Google Earth
PENNSYLVANIA
MARYLAND
1985
Imagery Date: 2/7/2024 39°44'28.17" N 76°17'14.87" W elev 359 ft eye alt 22160 ft

APPENDIX 4

TRANSOURCE PENNSYLVANIA, LLC

FERC FORM No. 1

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Transource Pennsylvania, LLC	Year/Period of Report End of: 2023/ Q4

FERC FORM NO. 1 (REV. 02-04)

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Transource Pennsylvania, LLC		02 Year/ Period of Report End of: 2023/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373		
05 Name of Contact Person Jason M. Johnson		06 Title of Contact Person Accountant
07 Address of Contact Person (Street, City, State, Zip Code) 1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373		
08 Telephone of Contact Person, Including Area Code (614) 716-1000	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/09/2024

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Jeffrey W. Hoersdig	03 Signature Jeffrey W. Hoersdig	04 Date Signed (Mo, Da, Yr) 04/09/2024
02 Title Assistant Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	N/A
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	N/A
50	**Transmission of Electricity by Others**	332	N/A
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	N/A
55	**Distribution of Salaries and Wages**	354	N/A
56	**Common Utility Plant and Expenses**	356	N/A
57	**Amounts included in ISO/RTO Settlement Statements**	397	N/A
58	**Purchase and Sale of Ancillary Services**	398	N/A
59	**Monthly Transmission System Peak Load**	400	N/A
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	N/A
61	**Electric Energy Account**	401a	N/A
62	**Monthly Peaks and Output**	401b	N/A
63	**Steam Electric Generating Plant Statistics**	402	N/A
64	**Hydroelectric Generating Plant Statistics**	406	N/A
65	**Pumped Storage Generating Plant Statistics**	408	N/A
66	**Generating Plant Statistics Pages**	410	N/A
66.1	**Energy Storage Operations (Large Plants)**	414	
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	N/A
68	**Transmission Lines Added During Year**	424	N/A
69	**Substations**	426	N/A
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Page 2

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey W. Hoersdig Assistant Controller

1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Delaware - July 28, 2016

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - Ohio, Pennsylvania

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?
(1)
☐ Yes

(2)
☑ No

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Transource Energy, LLC controls 100% of the Respondent as of December 31, 2023.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Not Applicable			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	President	Robert W. Bradish		2023-05-09	
2	Secretary	John W. Seidensticker		2023-05-15	
3	Secretary	Randy G. Ryan			2023-01-06
4	President	Michael L. Deggendorf			2023-05-09
5	Senior Vice President	Chad A. Heitmeyer			
6	Vice President (GPE)	Denise Buffington			
7	Vice President	David E. Rupert			
8	Treasurer	Julie A. Sherwood			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Kevin E. Bryant (Manager)	Kansas City, Missouri	false	false
2	Stephan T. Haynes (Manager)	Columbus, Ohio	false	false
3	Toby L. Thomas (Manager)	Columbus, Ohio	false	false
4	Steven J. Vetsch (Manager)	Kansas City, Missouri	false	false

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	PJM OATT Attachment H-29	ER17-419

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20230630-5424	06/30/2023	ER17-419	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-30
2	20231002-5383	10/02/2023	ER17-419	AEP PJM OATT Annual Formula Rate	PJM OATT Attachment H-30

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary capital ratio.

None
None
None
None
None
None
None
None
None
None
Steven J. Vetsch elected as Manager (GPE) on Jan.6, 2023. Randy G. Ryan resigned as Secretary on Jan. 6, 2023. Kate Sturgess elected as controller on May 09, 2023. Robert W. Bradish elected as President on May 09, 2023. Joseph M. Buonaiuto resigned as Controller on May 09, 2023. Michael L. Deggendorf resigned as President on May 09, 2023. John W. Seidensticker elected as Secretary on May 15, 2023. John W. Seidensticker resigned as Assistant Secretary on May 15, 2023. Toby L.Thomas resigned as Manager on November 29, 2023.
Proprietary capital ratio exceeds 30%

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	731,613	639,570
3	Construction Work in Progress (107)	200	91,172,664	84,332,885
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		91,904,277	84,972,455
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	318,265	243,425
6	Net Utility Plant (Enter Total of line 4 less 5)		91,586,012	84,729,030
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		91,586,012	84,729,030
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)			
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,734,509	3,098,168
36	Special Deposits (132-134)		500,000	500,000
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		71,360	561,705
41	Other Accounts Receivable (143)		617,816	
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)			
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		4,153	32,344
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227		
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		21,149	16,302
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		2,948,987	4,208,519
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)			
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	2,369,968	
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	129,211	209,176
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234	772,903	1,774,237
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		3,272,082	1,983,413
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		97,807,080	90,920,962

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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250		
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	30,604,557	20,289,083
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	15,382,666	10,296,882
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		45,987,223	30,585,965
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	47,200,000	43,000,000
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		47,200,000	43,000,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)			
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			2,009,728
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)			
35	Total Other Noncurrent Liabilities (lines 26 through 34)			2,009,728
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		1,172,266	2,888,192
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		296,330	609,832
41	Customer Deposits (235)			
42	Taxes Accrued (236)	262	883,347	5,011,570
43	Interest Accrued (237)			
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)			
48	Miscellaneous Current and Accrued Liabilities (242)		1,740,799	6,902,937
49	Obligations Under Capital Leases-Current (243)			

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		4,092,742	15,412,531
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	968	
60	Other Regulatory Liabilities (254)	278		339,988
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		53,610	62,381
64	Accum. Deferred Income Taxes-Other (283)		472,537	(489,632)
65	Total Deferred Credits (lines 56 through 64)		527,115	(87,263)
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		97,807,080	90,920,961

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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	10,854,166	7,285,945			10,854,166	7,285,945				
3	Operating Expenses											
4	Operation Expenses (401)	320	1,042,175	582,178			1,042,175	582,178				
5	Maintenance Expenses (402)	320	16,607	9,588			16,607	9,588				
6	Depreciation Expense (403)	336										
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	137,182	106,332			137,182	106,332				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)											
13	(Less) Regulatory Credits (407.4)											
14	Taxes Other Than Income Taxes (408.1)	262										
15	Income Taxes - Federal (409.1)	262	(489,190)	1,085,601			(489,190)	1,085,601				
16	Income Taxes - Other (409.1)	262	684,628	185,353			684,628	185,353				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
17	Provision for Deferred Income Taxes (410.1)	234, 272	3,179,140	1,104,246			3,179,140	1,104,246				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	1,562,605	928,622			1,562,605	928,622				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,007,937	2,144,677			3,007,937	2,144,677				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		7,846,229	5,141,268			7,846,229	5,141,268				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)											
34	(Less) Expenses of Nonutility Operations (417.1)											
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		87,063	10,934								
38	Allowance for Other Funds Used During Construction (419.1)											
39	Miscellaneous Nonoperating Income (421)		(116,187)									
40	Gain on Disposition of Property (421.1)											
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		(29,124)	10,934								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
44	Miscellaneous Amortization (425)											
45	Donations (426.1)											
46	Life Insurance (426.2)											
47	Penalties (426.3)			9								
48	Exp. for Certain Civic, Political & Related Activities (426.4)											
49	Other Deductions (426.5)		8	2,381								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8	2,390								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262										
53	Income Taxes-Federal (409.2)	262	(5,568)	1,617								
54	Income Taxes-Other (409.2)	262	(2,619)	854								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	(1,791)									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272										
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(9,978)	2,471								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(19,153)	6,073								
61	Interest Charges											
62	Interest on Long-Term Debt (427)											
63	Amort. of Debt Disc. and Expense (428)		79,965	96,150								
64	Amortization of Loss on Reaquired Debt (428.1)											
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		2,647,926	1,120,598								
68	Other Interest Expense (431)		13,400	400,274								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
70	Net Interest Charges (Total of lines 62 thru 69)		2,741,291	1,617,022								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		5,085,784	3,530,319								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		5,085,784	3,530,319								
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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		10,296,882	6,766,563
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		5,085,784	3,530,319
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		15,382,666	10,296,882
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		15,382,666	10,296,882
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	5,085,784	3,530,319
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	137,182	106,332
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of		
8	Deferred Income Taxes (Net)	1,614,744	175,624
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(99,280)	284,827
11	Net (Increase) Decrease in Inventory		
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(3,281,397)	1,779,026
14	Net (Increase) Decrease in Other Regulatory Assets	(2,369,968)	158,236
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[a](3,360,350)	(230,912)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	(2,273,285)	5,803,452
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(9,290,374)	(4,801,381)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(9,290,374)	(4,801,381)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
53	Other (provide details in footnote):		
53.1	Other (provide details in footnote):		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(9,290,374)	(4,801,381)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	4,200,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contributions from Parent	6,000,000	
70	Cash Provided by Outside Sources (Total 61 thru 69)	10,200,000	
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	10,200,000	
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(1,363,659)	1,002,071
88	Cash and Cash Equivalents at Beginning of Period	3,098,168	2,096,097
90	Cash and Cash Equivalents at End of Period	1,734,509	3,098,168
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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	Column (b) 2023 Cash Flow Incr / (Decr)	Column (c) 2022 Cash Flow Incr / (Decr)
Prepayments	$ (4,848)	$ (2,026)
Other Deferred Debits, Net	79,965	(108,976)
Proprietary Capital, Net	3,735,432	—
Accumulated Provisions - Misc	(2,009,728)	(54,068)
Current and Accrued Liabilities, Net	(5,162,139)	(65,842)
Other Deferred Credits, Net	968	—
Total	**$ (3,360,350)**	**$ (230,912)**

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
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 subsidiaries and affiliates.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Equity Funds Used During Construction.
ATRR	Annual transmission revenue requirement.
CWIP	Construction Work in Progress.
Evergy, Inc.	A public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri.
Evergy Metro, Inc.	A wholly-owned subsidiary of Evergy, Inc., provides certain support services to Transource Energy and subsidiaries.
Evergy Transmission Company, LLC	A wholly-owned subsidiary of Evergy, Inc., owns 13.5% of Transource Energy, LLC.
Excess ADIT	Excess Accumulated Deferred Income Taxes.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting Principles Generally Accepted in the United States of America.
OATT	Open Access Transmission Tariff.
PAPUC	Pennsylvania Public Utility Commission.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas. Transource Pennsylvania is a member of PJM. PJM is a FERC approved RTO.
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.
Transource Energy	Transource Energy, LLC, an AEP subsidiary formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Maryland	A 100% wholly-owned subsidiary of Transource Energy.
Transource Pennsylvania	A 100% wholly-owned subsidiary of Transource Energy.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Transource Pennsylvania was established to build and own transmission facilities in Pennsylvania. Transource Energy owns all of Transource Pennsylvania's outstanding equity. AEP Transmission Holdco and Evergy Transmission Company, LLC hold 86.5% and 13.5% membership interests in Transource Energy, respectively.

AEPSC and Evergy Metro, Inc. provide services to Transource Energy through service agreements. Transource Pennsylvania does not have employees.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The FERC regulates Transource Pennsylvania's rates and is permitted to review and audit Transource Pennsylvania's books and records. The FERC regulates the affiliated transactions of Transource Pennsylvania, including affiliated transactions involving AEPSC and Evergy Metro, Inc. billings at cost under the 2005 Public Utility Holding Company Act and the Federal Power Act.

The FERC has issued orders authorizing the inclusion of the Transource Pennsylvania formula rate and transmission revenue requirement in the OATT administered by PJM. The FERC orders implemented an ATRR for Transource Pennsylvania. Under this revenue requirement, Transource Pennsylvania makes annual filings in order to recover prudently incurred costs (including amortization of the pre-commercial cost regulatory asset) and an allowed return from wholesale transmission customers of PJM. An annual rate filing is made for each calendar year using estimated costs, which is used to determine the billings to PJM ratepayers. The annual rate filing is compared to actual costs with any under- or over-recovery being trued-up with interest and recovered or refunded in future year rates. The FERC has approved the use of a formula rate methodology for recovery of all prudently incurred operation expenses and maintenance expenses, a return on debt and equity on all capital expenditures in connection with Transource Pennsylvania's projects as well as an income tax allowance. As a result, Transource Pennsylvania recognizes revenue when the underlying performance obligations are satisfied.

Basis of Accounting

Transource Pennsylvania's accounting is subject to the requirements of the FERC and the PAPUC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The inclusion of income taxes as a component of the financial statements rather than the exclusion of income taxes due to structure as a limited liability company.
- The classification of interest on regulated finance leases as Operating Expense instead of Other Income (Expense).
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of carrying charges for transmission over/under recovery in non-operating income rather than non-operating expenses.

Accounting for the Effects of Cost-Based Regulation

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

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, long-lived asset impairment, the effects of regulation including formula rate revenues, long-lived asset recovery and the effects of contingencies. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents on the statements of cash flows include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

	2023	2022
For the Years Ended December 31,	**(in thousands)**	
Cash Paid for Interest (Net of Capitalized Amounts)	2,779	$ 1,049
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	451	2,747

Accounts Receivable

Accounts receivable primarily includes receivables from PJM based on the monthly allocation of the tariff rates that were authorized in the FERC order.

Transmission Property

Transmission property is stated at original cost. Additions, major replacements and betterments are added to the property accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as poles, transformers, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of an affiliated company as a proxy of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs, when incurred, will be charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain the transmission property is included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

CWIP and AFUDC

The FERC issued an order approving Transource Pennsylvania's request to include CWIP in recoverable rate base, instead of accruing AFUDC during construction. If this incentive had not been granted, Transource Pennsylvania would have capitalized $7.3 million and $3.8 million of AFUDC in CWIP during 2023 and 2022, respectively. As of December 31, 2023 and 2022, Transource Pennsylvania's Utility Plant would have been $18.1 million and $10.9 million higher, respectively, as a result of AFUDC if it had been capitalized during construction.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Accounts Receivable from Associated Companies, Accounts Payable to Associated Companies, Customer Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

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.

Revenue Recognition

Regulatory Accounting

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

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

Transmission Revenue Accounting

Pursuant to an order approved by the FERC, Transource Pennsylvania is included in the OATT administered by PJM. The FERC order implemented an ATRR for Transource Pennsylvania. Under this requirement, AEPSC, on behalf of Transource Pennsylvania, makes annual filings in order to recover prudently incurred costs (including amortization of the formation cost regulatory asset) and an allowed return on plant in service and CWIP. An annual formula rate filing is made for each calendar year using estimated costs, which is used to determine the billings to PJM ratepayers. The estimated costs in the annual rate filing is compared to actual costs with any over- or under-recovery being trued-up with carrying charges and recovered or refunded in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by Transource Pennsylvania in the fourth quarter of each calendar year and a final annual true-up is recognized by Transource Pennsylvania in the second quarter of each calendar year following the filing of annual FERC reports.
Transource Pennsylvania recognizes revenue when the underlying performance obligations to design, develop, construct, operate and maintain the transmission plant are satisfied and as it incurs recoverable costs and earns the allowed return on plant in service and CWIP on a monthly basis. See Note 11 - Revenue from Contracts with Customers for additional information.

Income Taxes

Transource Pennsylvania is a tax partnership that is owned 86.5% by AEP Transmission Holdco and 13.5% by Evergy Transmission Company, LLC. As a result, Transource Pennsylvania is not liable for federal or state income taxes. The income tax effect of Transource Pennsylvania's activities flows directly to AEP Transmission Holdco (a single-member limited liability company, taxable as a corporation) and Evergy Transmission Company, LLC (a single-member limited liability company). AEP Transmission Holdco and Evergy Transmission Company, LLC's tax owner entity report their respective shares of Transource Pennsylvania's earnings, gains, losses, deductions and tax credits on their respective federal and state income tax returns.

Transource Pennsylvania is allowed, however, to recover in rates, as a component of its cost of service, the amount of income taxes that are the responsibility of AEP Transmission Holdco and Evergy Transmission Company, LLC's tax owner entity. Transource Pennsylvania is also required to adjust its rate base by the amount of deferred tax assets and liabilities it would have recorded if it were a taxable corporation.

Transource Pennsylvania will continue to work with the FERC to determine the appropriate mechanism and time period over which to provide the benefits of Tax Reform to customers. Transource Pennsylvania expects the mechanism and time period to provide the benefits of Tax Reform to customers will reduce future cash flows, net income and may impact financial condition.

Subsequent Events

Management reviewed subsequent events through April 9, 2024, the date that Transource Pennsylvania's 2023 FERC Form 1 was available to be issued.

2. NEW ACCOUNTING STANDARDS

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 Transource Pennsylvania's business. There are no new standards expected to have a material impact on Transource Pennsylvania's financial statements.

3. RATE MATTERS

Transource Pennsylvania is involved in rate and regulatory proceedings at the FERC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Recent significant rate orders and pending rate filings are addressed in this note.

Formula Rate

Transource Pennsylvania submits an annual filing with PJM which establishes its projected transmission revenue requirement (PTRR). The new rates become effective at the beginning of the year and are subject to refund and true-up. The formula rates establish rates for one year and also include a true-up calculation for the prior year's billings, allowing for (over)/under-recovery of the PTRR. The following table summarizes Transource Pennsylvania's PTRR with remaining (over)/under-recovery balances:

				Remaining (Over)/Under-Recovery	
Year		**PTRR**	**Total (Over)/Under-Recovery**	**December 31, 2023 (a)**	**December 31, 2022**
			(in thousands)		
2022		9,067	(1,878)	(1,827)	(2,010)
2023	(c)	8,319	2,370 (b)	2,370	—
2024		10,192	— (b)	—	—

(a) As of December 31, 2023, the remaining (over)/under-recovery balance was recorded as $(93) thousand as Accounts Payable to Associated Companies, $(1.7) million as Miscellaneous Current and Accrued Liabilities and $2.4 million as Regulatory Assets.
(b) These amounts represent estimated (over)/under-recovered revenues, subject to refund and true-up. The true-up of these revenues will be incorporated in a future PTRR that is filed in the third quarter of each calendar year. The 2023 true-up will be incorporated in the 2025 PTRR and the 2024 true-up will be incorporated in the 2026 PTRR.
(c) The 2023 PTRR included a prior year adjustment of $490 thousand related to the 2020 true-up. This adjustment was refunded throughout 2023 and was excluded from the table above. The remaining over-recovered balances recorded in Miscellaneous Current and Accrued Liabilities were $0 and $478 thousand as of December 31, 2023 and 2022, respectively.

Independence Energy Connection Project

In 2016, PJM approved the Independence Energy Connection Project (IEC) and included it in its Regional Transmission Expansion Plan to alleviate congestion. Transource Energy has an ownership interest in the IEC, which is located in Maryland and Pennsylvania, through its Transource Maryland and Transource Pennsylvania subsidiaries. In June 2020, the Maryland Public Service Commission approved a Certificate of Public Convenience and Necessity to construct the portion of the IEC in Maryland for Transource Maryland. In May 2021, the PAPUC denied the IEC certificate for siting and construction of the portion in Pennsylvania for Transource Pennsylvania. Transource Pennsylvania appealed the PAPUC ruling in Pennsylvania state court and challenged the ruling before the United States District Court for the Middle District of Pennsylvania. In May 2022, the Pennsylvania state court issued an order affirming the PAPUC decision as to state law claims. In December 2023, the United States District Court for the Middle District of Pennsylvania granted summary judgment in favor of Transource Pennsylvania, finding that the PAPUC decision violated federal law and the United States Constitution. In January 2024, the PAPUC filed an appeal with the United States Court of Appeals for the Third Circuit. Additional regulatory proceedings before the PAPUC are expected to resume in 2024.
In September 2021, PJM notified Transource Energy that the IEC was suspended to allow for the regulatory and related appeals process to proceed in an orderly manner without breaching milestone dates in the project agreement. At that time, PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. PJM continues to evaluate reliability and market efficiency in the area. As of December 31, 2023, Transource Pennsylvania's share of the IEC capital expenditures is approximately $91.6 million located in Net Utility Plant on its 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.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31,		Remaining
	2023	**2022**	**Recovery Period**
Regulatory Assets:	**(in thousands)**		
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
FERC Formula Rates Under-Recovery	$ 2,370	$ —	2 years
Total Regulatory Assets Approved for Recovery	2,370	—	
Total FERC Account 182.3 Regulatory Assets	$ 2,370	$ —	

	December 31, 2023	December 31, 2022	Remaining Recovery Period
Regulatory Liabilities:	(in thousands)		
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Tax Liabilities (a)	$ —	$ 340	(b)
Total Regulatory Liabilities Pending Final Regulatory Determination	—	340	
Total FERC Account 254 Regulatory Liabilities	$ —	$ 340	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Transource Pennsylvania is subject to certain claims and legal actions arising in its ordinary course of business. In addition, Transource Pennsylvania's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Transource Pennsylvania 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, Transource Pennsylvania 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.

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

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 construction contracts, insurance programs, security deposits and debt service reserves.

AEP has $4 billion and $1 billion revolving credit facilities due in March 2027 and 2025, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2023, no letters of credit were issued under the revolving credit facilities.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under five uncommitted facilities totaling, as of December 31, 2023, $450 million. As of December 31, 2023, Transource Pennsylvania's maximum future payments for letters of credit issued under the uncommitted facilities was $4.4 million with a maturity date of October 2024.

Indemnifications and Other Guarantees

Transource Pennsylvania enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, 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. As of December 31, 2023, there were no material liabilities recorded for any indemnifications.

CONTINGENCIES

Insurance and Potential Losses

Transource Pennsylvania maintains property insurance coverage normal and customary for an electric utility, subject to various deductibles. Insurance includes coverage for all risks of physical loss or damage to Transource Pennsylvania property, subject to insurance policy conditions and exclusions. Covered property generally includes substations, facilities and inventories. Excluded property generally includes transmission lines, poles and towers. Transource Pennsylvania's insurance program also generally provides coverage against loss arising from certain claims made by third-parties in excess of retentions absorbed by Transource Pennsylvania. Coverage is generally provided by a combination of various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

6. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-Term Debt

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 book values and fair values of Transource Pennsylvania's Long-Term Debt are summarized in the following table:

December 31, 2023		December 31, 2022	
Book Value	**Fair Value**	**Book Value**	**Fair Value**
(in thousands)			
$ 47,200	$ 47,200	$ 43,000	$ 43,000

7. INCOME TAXES

Income Tax Expense

The details of Transource Pennsylvania's income taxes as reported are as follows:

	Years Ended December 31, 2023	Years Ended December 31, 2022
Charged (Credited) to Operating Expenses, Net:	(in thousands)	
Current	$ 195	$ 1,271
Deferred	1,617	176
Total	1,812	1,447
Charged to Nonoperating Income, Net:		
Current	(8)	2
Deferred	(2)	—
Total	(10)	2
Income Tax Expense	$ 1,802	$ 1,449

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31,	
	2023	2022
	(in thousands)	
Net Income	$ 5,086	$ 3,530
Income Tax Expense	1,802	1,449
Pretax Income	$ 6,888	$ 4,979
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 1,446	$ 1,046
Increase in Income Taxes Resulting from the following Items:		
State and Local Income Taxes, Net	356	404
Other	—	(1)
Income Tax Expense	$ 1,802	$ 1,449
Effective Income Tax Rate	26.2 %	29.1 %

Net Deferred Tax Asset

The following table shows elements of Transource Pennsylvania's net deferred tax assets and significant temporary differences:

	December 31,	
	2023	2022
	(in thousands)	
Deferred Tax Assets	$ 773	$ 1,774
Deferred Tax Liabilities	(526)	427
Net Deferred Tax Assets	$ 247	$ 2,201
Property Related Temporary Differences	$ (55)	$ (66)
Deferred State Income Taxes	73	333
Regulatory Assets	(473)	—
Net Operating Loss Carryforward	356	
Provision for Refund	346	1,849
All Other, Net	—	85
Net Deferred Tax Assets	$ 247	$ 2,201

8. <u>FINANCING ACTIVITIES</u>

Long-Term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average Interest Rate as of December 31, 2023	Interest Rate Ranges as of December 31, 2023	Interest Rate Ranges as of December 31, 2022	Outstanding as of December 31, 2023	Outstanding as of December 31, 2022
					(in thousands)	
Intercompany Notes Payable	2025	6.34%	6.34%	5.17%	$ 47,200	$ 43,000
Total Long-Term Debt					$ 47,200	$ 43,000

Dividend Restrictions

Transource Pennsylvania pays dividends to Transource Energy provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of Transource Pennsylvania to transfer funds to Transource Energy in the form of dividends.

All of the dividends declared by Transource Pennsylvania are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. As of December 31, 2023, the maximum amount of restricted net assets of Transource Pennsylvania that may not be distributed to Transource Energy in the form of a loan, advance or dividend was $30.6 million.

9. <u>RELATED PARTY TRANSACTIONS</u>

Affiliated Transmission Revenues

Subsidiaries of AEP that are load serving entities within the PJM region incurred $565 thousand and $389 thousand in PJM transmission services costs related to Transource Pennsylvania that were billed to them in accordance with the OATT for the years ended December 31, 2023 and 2022, respectively. Transource Pennsylvania recorded these affiliated transmission revenues in Operating Revenues.

Service Agreements

AEPSC and Evergy Metro, Inc. each provide managerial and professional services to Transource Energy under service agreements. These services agreements are pending the approval of the PAPUC. The costs of the services are billed to Transource Energy by AEPSC and Evergy Metro, Inc., on a direct-charge basis whenever possible and on a reasonable basis of proration for services that benefit multiple companies. The billings for services are made on a cost basis on the same basis as such charges are determined for equivalent services that AEPSC provides to other AEP affiliates and that Evergy Metro, Inc. provides to other Evergy Metro, Inc. affiliates, including reasonable allocations of overhead. Billings from AEPSC and Evergy Metro, Inc. are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. AEPSC, Evergy Metro, Inc. and their billings are subject to regulation by the FERC under the Public Utility Holding Company Act of 2005. Transource Energy bills Transource Pennsylvania for these services under a service agreement. Transource Pennsylvania's total billings from Transource Energy related to AEPSC services were $1.4 million and $564 thousand for the years ended December 31, 2023 and 2022, respectively. Transource Pennsylvania did not have material billings from Evergy Metro, Inc. for services for the years ended December 31, 2023 and 2022, respectively.

Affiliated Long-Term Debt

For the years ended December 31, 2023 and 2022, Transource Pennsylvania's intercompany borrowings from Transource Energy increased by $4.2 million and $0, respectively. See Note 8 - Financing Activities for additional information.

10. <u>TRANSMISSION PROPERTY</u>

Depreciation

Transource Pennsylvania will provide for depreciation of transmission property on a straight-line basis over the estimated useful lives of property as projects are completed and placed in-service. Transource Pennsylvania's FERC approved composite depreciation rates for depreciable assets range from 1.38% to 6.67%. Transource Pennsylvania had $732 thousand and $640 thousand of depreciable assets in-service as of December 31, 2023 and 2022, respectively.

Asset Retirement Obligations (ARO)

Transource Pennsylvania has identified, but not recognized, ARO liabilities related to electric transmission assets as a result of certain easement agreements for access to assets constructed on property owned by third parties. Generally, such easements are perpetual and require only the retirement and removal of the assets upon the cessation of the property's use. The retirement obligation is not estimable since Transource Pennsylvania plans to use the electric transmission assets indefinitely. The retirement obligation would only be recognized if Transource Pennsylvania abandons or ceases the use of specific easements, which is not expected.

11. <u>REVENUE FROM CONTRACTS WITH CUSTOMERS</u>

Disaggregated Revenues from Contracts with Customers

Transource Pennsylvania's revenue consists of affiliated and nonaffiliated transmission revenues from contracts with customers. The annual transmission revenue true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations." Transource Pennsylvania alternative revenues were $9.8 million and $157 thousand for the years ended December 31, 2023 and 2022.

Performance Obligations

Transource Pennsylvania has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. Transource Pennsylvania elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for Transource Pennsylvania are summarized as follows:

Transmission Revenues

Transource Pennsylvania has performance obligations to design, develop, construct, operate and maintain transmission plant for the ultimate purpose of transmission of electricity to wholesale customers through assets owned and operated by Transource Pennsylvania. The performance obligation to provide transmission services in each RTO is partially fixed for a period of one year or less. Payments from PJM for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly.

Transource Pennsylvania collects revenues through transmission formula rates. The FERC-approved rates establish the ATRR and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR.

Contract Assets and Liabilities

Contract assets are recognized when Transource Pennsylvania has 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. Transource Pennsylvania did not have any material contract assets as of December 31, 2023 and 2022.

When Transource Pennsylvania receives 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. Transource Pennsylvania did not have any material contract liabilities as of December 31, 2023 and 2022.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on Transource Pennsylvania's balance sheets in Customer Accounts Receivable. Transource Pennsylvania's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2023 and 2022.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on Transource Pennsylvania's balance sheets were immaterial as of December 31, 2023 and 2022.

Contract Costs

Contract costs to obtain or fulfill a contract for Transource Pennsylvania are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current assets and deferred debits on the balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on the statements of income. Transource Pennsylvania did not have material contract costs as of December 31, 2023 and 2022.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								3,530,319	3,530,319
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								5,085,784	5,085,784
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	731,613	731,613					
4	Property Under Capital Leases							
5	Plant Purchased or Sold							
6	Completed Construction not Classified							
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	731,613	731,613					
9	Leased to Others							
10	Held for Future Use							
11	Construction Work in Progress	91,172,664	91,172,664					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	91,904,277	91,904,277					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	318,265	318,265					
15	Net Utility Plant (13 less 14)	91,586,012	91,586,012					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation							
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	318,265	318,265					
22	Total in Service (18 thru 21)	318,265	318,265					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	318,265	318,265					

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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	639,570	154,386	62,343			731,613
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	639,570	154,386	62,343			731,613
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights						
9	(311) Structures and Improvements						
10	(312) Boiler Plant Equipment						
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units						
13	(315) Accessory Electric Equipment						
14	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)						
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights						
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements						
50	(353) Station Equipment						
51	(354) Towers and Fixtures						
52	(355) Poles and Fixtures						
53	(356) Overhead Conductors and Devices						
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices						
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)						
59	4. Distribution Plant						
60	(360) Land and Land Rights						
61	(361) Structures and Improvements						
62	(362) Station Equipment						
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures						
65	(365) Overhead Conductors and Devices						
66	(366) Underground Conduit						
67	(367) Underground Conductors and Devices						
68	(368) Line Transformers						
69	(369) Services						
70	(370) Meters						
71	(371) Installations on Customer Premises						
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems						
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)						
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights						
87	(390) Structures and Improvements						
88	(391) Office Furniture and Equipment						
89	(392) Transportation Equipment						
90	(393) Stores Equipment						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
91	(394) Tools, Shop and Garage Equipment						
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment						
94	(397) Communication Equipment						
95	(398) Miscellaneous Equipment						
96	SUBTOTAL (Enter Total of lines 86 thru 95)						
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)						
100	TOTAL (Accounts 101 and 106)	639,570	154,386	62,343			731,613
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	639,570	154,386	62,343			731,613

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
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3						
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45						
46						
47	TOTAL					

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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
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10				
11				
12				
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14				
15				
16				
17				
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20				
21	Other Property:			
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24				
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Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
47	TOTAL			

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	IEC Project Pennsylvania	91,086,461
2	Other Minor Projects Which is under 5% or $1,000,000	86,203
43	Total	91,172,664

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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)				
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired				
13	Cost of Removal				
14	Salvage (Credit)				
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)				
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)				
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission				
26	Distribution				
27	Regional Transmission and Market Operation				
28	General				
29	TOTAL (Enter Total of lines 20 thru 28)				

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
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Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
42	Total Cost of Account 123.1 $		Total					
				Page 224-225				

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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)			
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies			

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
	Page 228(ab)-229(ab)a												

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
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12						
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22						
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25						
26						
27						
28						
20	TOTAL					

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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20	Total				
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	Total				
40	Grand Total				

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 109 Deferred FIT			190		
2	2023 PJM Transmission True Up, Amortization Period: 01/2025 - 12/2025		2,369,968	421, 456		2,369,968
44	TOTAL		2,369,968			2,369,968

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Unamortized Credit Line FeesAmortizing through September 2025	209,176		428	79,965	129,211
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	209,176				129,211

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	NOL - DEFERRED TAX ASSET RECLASS		176,903
3	INSURANCE PREMIUMS ACCRUED	(3,423)	(4,220)
4	REG ASSET-FERC Formula Rates Under Recvr		24,835
5	NOL-STATE C/F-DEF TAX ASSET-L/T - PA		226,675
6	PROVS POSS REV REFDS-A/L	1,849,141	346,035
7	Other	(88,612)	2,675
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,757,106	772,903
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	[a]17,131	
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,774,237	772,903

Notes

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 17 Other - Detail		Balance at Beginning of Year		Balance at End of Year
Acc Def Income Taxes	-		-	
Non Utility Items-190.2		—		—
SFAS 109-Regulatory Assets - 190.3 & 190.4		17,131		—
Total	$	17,131	$	—
Line 18				
Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :				
Balance at Beginning of Year	$	1,774,237		
(Less) Amounts Debited to:				
(a) Account 410.1		(1,704,175)		
(b) Account 410.2		—		
(c) 1823/254		(38,926)		
(Plus) Amounts Credited to:				
(a) Account 411.1		719,972		
(b) Account 411.2		—		
(c) 1823/254		21,795		
Balance at End of Year	$	772,903		

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2										
3										
4										
5	Total									
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	19,120,463
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	6,000,000
4	Ending Balance Amount	25,120,463
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	1,168,620
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	4,315,474
16	Ending Balance Amount	5,484,094
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	30,604,557

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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)
1	Bonds (Account 221)										
2											
3											
4											
5	Subtotal										
6	Reacquired Bonds (Account 222)										
7											
8											
9											
10	Subtotal										
11	Advances from Associated Companies (Account 223)										
12	Notes Payable to Afffiliated Company - Transource Energy, LLC FERC Authority: ES21-23-000		200,000,000					10/04/2022	10/04/2025	10/04/2022	10/04/2025
13	Subtotal		200,000,000								
14	Other Long Term Debt (Account 224)										
15											
16											
17											
18	Subtotal										
33	TOTAL		200,000,000								

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12	47,200,000	2,647,926
13	47,200,000	2,647,926
14		
15		
16		
17		
18		
33	47,200,000	[a]2,647,926

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: InterestExpenseOnLongTermDebtIssued
The difference between the total interest on this schedule and the total of account 430 is due to interest on short-term advances from the AEP Money Pool.

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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	5,085,784
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	[a](2,521,413)
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		

Line No.	Particulars (Details) (a)	Amount (b)
44		
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FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

Net Income for the Year per Page 117	5,086
Federal Income Taxes	1,320
State Income Taxes	482
Pre-Tax Book Income	6,888
Increase (Decrease) in Taxable Income resulting from:	
Allowance for Funds Used During Construction and Other Differences	
Excess Tax vs Book Depreciation	3
Book Accruals	(5)
Book Deferals	(2,370)
Tax Deferrals	34
REVENUE REFUNDS	(7,071)
Federal Taxable Income before State Income Taxes	(2,521)
Less: State Income Taxes	—
Federal Tax Net Income - Estimated Current Year Taxable Income	(2,521)
Computation of Tax *	
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 21%	(529)
NOL Reclass	—
Estimated Current Federal Income Taxes (Net)	(529)
Adjustments of Prior year's Accruals (Net)	(142)
011G NOL - RECLASS TO/FROM DEFD TAX ASSET	(177)
Estimated Current Federal Income Taxes(Net)	(494)

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Federal Tax	Federal Tax			3,750,706		(340,570)			3,410,136	
2	Federal Tax	Federal Tax	PA				(2,755,066)			(2,755,066)	
3	**Subtotal Federal Tax**				3,750,706		(3,095,636)			655,070	
4	State Tax	State Tax	PA	2020	433,131		(433,131)				
5	State Tax	State Tax	PA	2021	547,236		(547,236)				
6	State Tax	State Tax	PA	2022	186,208					186,208	
7	State Tax	State Tax	PA	2023			(52,220)			(52,220)	
8	**Subtotal State Tax**				1,166,575		(1,032,587)			133,988	
9	Sales And Use Tax	Sales And Use Tax	PA	2020	13,765					13,765	
10	Sales And Use Tax	Sales And Use Tax	PA	2021	80,524					80,524	
11	**Subtotal Sales And Use Tax**				94,289					94,289	
40	TOTAL				5,011,570		(4,128,223)			883,347	

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) **(l)**	**Extraordinary Items (Account 409.3)** **(m)**	**Adjustment to Ret. Earnings (Account 439)** **(n)**	**Other** **(o)**
1	(489,190)			148,620
2				(2,755,065)
3	(489,190)			(2,606,445)
4				(433,131)
5				(547,236)
6				
7	684,628			(736,848)
8	684,628			(1,717,215)
9				
10				
11				
40	195,438			(4,323,660)

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%				411.4					
3	4%				411.4					
4	7%				411.4					
5	10%		411.1		411.4					
6	State DITC		411.1		411.4					
7	30%				411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL									

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Other Deferred Credits				968	968
47	TOTAL				968	968

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other - SFAS 109						254		254		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	63,791	4,158	14,339					190		53,610
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	63,791	4,158	14,339							53,610
6	Other	(1,410)					1823/254	148	1823/254	1,558	
9	TOTAL Account 282 (Total of Lines 5 thru 8)	62,381	4,158	14,339				148		1,558	53,610
10	Classification of TOTAL										
11	Federal Income Tax	62,381	4,158	14,339				148		1,558	53,610
12	State Income Tax										
13	Local Income Tax										

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	EXCESS ADFIT 283 - UNPROTECTED.	(786)	786								
4	REG ASSET-FERC Formula Rates Under Recvr		497,693								497,693
5	EXCESS DSIT - UNPROTECTED PA	254,564	561,844	816,408							
6	PROVS POSS REV REFDS-A/L	(439,391)	352,848								(86,543)
7	Other	17,428	57,637	11,886				1,792	283		61,387
9	TOTAL Electric (Total of lines 3 thru 8)	(168,185)	1,470,808	828,294				1,792			472,537
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	(321,447)					1823/254	660,959	1823/254	982,406	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	(489,632)	1,470,808	828,294				662,751		982,406	472,537
20	Classification of TOTAL										
21	Federal Income Tax	(389,903)	706,607	92,856				662,751		984,198	545,295
22	State Income Tax	(99,730)	764,201	735,438						(1,791)	(72,758)
23	Local Income Tax										

NOTES

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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	SFAS 109 Deferred FIT	339,988		1,022,890	682,902	
41	TOTAL	339,988		1,022,890	682,902	

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Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales						
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)						
5	Large (or Ind.) (See Instr. 4)						
6	(444) Public Street and Highway Lighting						
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers						
11	(447) Sales for Resale						
12	TOTAL Sales of Electricity						
13	(Less) (449.1) Provision for Rate Refunds	(275,048)	1,801,651				
14	TOTAL Revenues Before Prov. for Refunds	275,048	(1,801,651)				
15	Other Operating Revenues						
16	(450) Forfeited Discounts						
17	(451) Miscellaneous Service Revenues						
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property						
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues						
22	(456.1) Revenues from Transmission of Electricity of Others	[a]10,579,117	9,087,597				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	10,579,117	9,087,597				
27	TOTAL Electric Operating Revenues	10,854,166	7,285,945				

Line12, column (b) includes $ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

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FOOTNOTE DATA

(a) Concept: RevenuesFromTransmissionOfElectricityOfOthers
Reference page 328 for Revenue details.

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(275,048)			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed - All Accounts					
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1											
2											
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15	Subtotal - RQ										
16	Subtotal-Non-RQ										
17	Total										

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)		
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	778,727	73,491
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	757	1,158
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	2,704	2,662
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses		4
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	948	1,566
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	36,765	218,726
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	819,901	297,607

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		1
103	(569.1) Maintenance of Computer Hardware	362	399
104	(569.2) Maintenance of Computer Software	14,700	8,267
105	(569.3) Maintenance of Communication Equipment	832	227
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	487	546
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines		
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	26	31
111	TOTAL Maintenance (Total of Lines 101 thru 110)	16,407	9,471
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	836,308	307,078
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		
135	(581) Load Dispatching		
136	(582) Station Expenses		
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses		
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses		
141	(587) Customer Installations Expenses		
142	(588) Miscellaneous Expenses		
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)		
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment		
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines		
150	(594) Maintenance of Underground Lines		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)		
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses		
161	(903) Customer Records and Collection Expenses		
162	(904) Uncollectible Accounts		
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)		
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses		
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)		
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	66,661	86,389
182	(921) Office Supplies and Expenses	20	1,450
183	(Less) (922) Administrative Expenses Transferred-Credit	7,618	
184	(923) Outside Services Employed	221,482	178,241
185	(924) Property Insurance		
186	(925) Injuries and Damages		
187	(926) Employee Pensions and Benefits	30	153
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	17,946	17,553
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		2
192	(930.2) Miscellaneous General Expenses	(76,246)	768
193	(931) Rents		15
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	222,274	284,571
195	Maintenance		
196	(935) Maintenance of General Plant	200	118
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	222,475	284,689
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,058,783	591,767

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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15	TOTAL						0	0	0	0

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (I), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY	
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)
1	PJM			FNO	PJM OATT					
35	TOTAL									

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1			[(a)]10,579,117	10,579,117
35			10,579,117	10,579,117

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Revenue earned from PJM per the revenue requirement for transmission services filed with FERC.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
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30					
31					
32					
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34					
35					
36					
37					
38					
39					
40					
41					
42					

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				
Page 331					

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Trustee fee	
7	Company Membership	235
8	Travel Expenses	480
9	Miscellaneous expenses	(76,961)
46	TOTAL	(76,246)

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			137,182		137,182
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant					
8	Distribution Plant					
9	Regional Transmission and Market Operation					
10	General Plant					
11	Common Plant-Electric					
12	TOTAL			137,182		137,182

B. Basis for Amortization Charges

Line 1, Column D represents amortization of capitalized software development cost over a 5 year life.

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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49							

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Miscellaneous Expenses		17,946	17,946			928	17,946				
46	TOTAL		17,946	17,946				17,946				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   A. Electric R, D and D Performed Internally:
      1. Generation
         a. hydroelectric
            i. Recreation fish and wildlife
            ii. Other hydroelectric
         b. Fossil-fuel steam
         c. Internal combustion or gas turbine
         d. Nuclear
         e. Unconventional generation
         f. Siting and heat rejection
      2. Transmission
         a. Overhead
         b. Underground
      3. Distribution
      4. Regional Transmission and Market Operation
      5. Environment (other than equipment)
      6. Other (Classify and include items in excess of $50,000.)
      7. Total Cost Incurred

   B. Electric, R, D and D Performed Externally:
      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      2. Research Support to Edison Electric Institute
      3. Research Support to Nuclear Power Groups
      4. Research Support to Others (Classify)
      5. Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	B(1): Research Support to Electrical	4 items under $50,000		4	566	4	
2	Research Council or the Electric						
3	Power Research Institute						

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production			
4	Transmission			
5	Regional Market			
6	Distribution			
7	Customer Accounts			
8	Customer Service and Informational			
9	Sales			
10	Administrative and General			
11	TOTAL Operation (Enter Total of lines 3 thru 10)			
12	Maintenance			
13	Production			
14	Transmission			
15	Regional Market			
16	Distribution			
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)			
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)			
21	Transmission (Enter Total of lines 4 and 14)			
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)			
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)			
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)			
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)			
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)			
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts			
96	TOTAL SALARIES AND WAGES			
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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
46	TOTAL				
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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	0	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	0
10	Purchases (other than for Energy Storage)	0			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	0			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January					
30	February					
31	March					
32	April					
33	May					
34	June					
35	July					
36	August					
37	September					
38	October					
39	November					
40	December					
41	Total	0	0			

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0
7	Plant Hours Connected to Load	0
8	Net Continuous Plant Capability (Megawatts)	0
9	When Not Limited by Condenser Water	0
10	When Limited by Condenser Water	0
11	Average Number of Employees	0
12	Net Generation, Exclusive of Plant Use - kWh	0
13	Cost of Plant: Land and Land Rights	0
14	Structures and Improvements	0
15	Equipment Costs	0
16	Asset Retirement Costs	0
17	Total cost (total 13 thru 20)	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0
19	Production Expenses: Oper, Supv, & Engr	0
20	Fuel	0
21	Coolants and Water (Nuclear Plants Only)	0
22	Steam Expenses	0
23	Steam From Other Sources	0
24	Steam Transferred (Cr)	0
25	Electric Expenses	0
26	Misc Steam (or Nuclear) Power Expenses	0
27	Rents	0
28	Allowances	0
29	Maintenance Supervision and Engineering	0
30	Maintenance of Structures	0
31	Maintenance of Boiler (or reactor) Plant	0
32	Maintenance of Electric Plant	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0
34	Total Production Expenses	0
35	Expenses per Net kWh	0.0000

35	**Plant Name**
36	Fuel Kind
37	Fuel Unit
38	Quantity (Units) of Fuel Burned
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year
41	Average Cost of Fuel per Unit Burned
42	Average Cost of Fuel Burned per Million BTU
43	Average Cost of Fuel Burned per kWh Net Gen
44	Average BTU per kWh Net Generation

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	0
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0
7	Plant Hours Connect to Load	0
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	0
10	(b) Under the Most Adverse Oper Conditions	0
11	Average Number of Employees	0
12	Net Generation, Exclusive of Plant Use - kWh	0
13	**Cost of Plant**	
14	Land and Land Rights	0
15	Structures and Improvements	0
16	Reservoirs, Dams, and Waterways	0
17	Equipment Costs	0
18	Roads, Railroads, and Bridges	0
19	Asset Retirement Costs	0
20	Total cost (total 13 thru 20)	0
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	0
24	Water for Power	0
25	Hydraulic Expenses	0
26	Electric Expenses	0
27	Misc Hydraulic Power Generation Expenses	0
28	Rents	0
29	Maintenance Supervision and Engineering	0
30	Maintenance of Structures	0
31	Maintenance of Reservoirs, Dams, and Waterways	0
32	Maintenance of Electric Plant	0
33	Maintenance of Misc Hydraulic Plant	0
34	Total Production Expenses (total 23 thru 33)	0
35	Expenses per net kWh	0

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Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1													
2													
3													
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Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
41													
42													
43													
44													
45													
46													
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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator’s own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)
1												
2												
3												
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6												
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32												
33												
34												
35	TOTAL			0	0	0	0	0	0	0	0	0

Line No.	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1							
2							
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34							
35	0	0	0		0	0	0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1									
2									
3									
4									
5									
6									
7									
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35									
36	TOTAL								

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Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	NOTHING TO REPORT											
36	TOTAL					0	0	0				

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1				
36				

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	NOTHING TO REPORT										
44	TOTAL		0		0	0	0				

Line No.	LINE COST					Construction
	Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(l)	(m)	(n)	(o)	(p)	(q)
1						
44						

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
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37									
38									
39									
40									
1	TotalTransmissionSubstationMember								
2	Total								

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
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8			
9			
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36			
37			
38			
39			
40			
1			0
2			0

Name of Respondent: Transource Pennsylvania, LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Construction Services	AEPSC	107, 108	310,001
3	Transmission Expenses - Operation	AEPSC	560, 561.2, 561.5, 563, 566, 920, 923	820,087
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21				
22				
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REDACTED

CONFIDENTIAL

APPENDIX 5

Second Amended and Restated Credit Agreement

REDACTED

CONFIDENTIAL

APPENDIX 6

Credit Opinion – Transource Energy, LLC

APPENDIX 7

AEP 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, 2024

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, 2024**
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

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 30, 2024
American Electric Power Company, Inc.	527,121,759
	($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, 2024

Part II. OTHER INFORMATION

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, 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 Energy Supply LLC	A nonregulated holding company for AEP’s competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
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 counterparties.
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.
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.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered Expanded Net Energy Cost deferral balance.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
ATM	At-the-Market.
CAA	Clean Air Act.
CCR	Coal Combustion Residual.
CO_2	Carbon dioxide and other greenhouse gases.
CODM	Chief Operating Decision Maker.
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.
CSAPR	Cross-State Air Pollution Rule.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII, DCC Fuel XVIII, DCC Fuel XIX and DCC Fuel XX 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.
DIR	Distribution Investment Rider.

Term	Meaning
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Equity Units	AEP's Equity Units issued in August 2020.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
GHG	Greenhouse gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
IRP	Integrated Resource Plan.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
MISO	Midcontinent Independent System Operator.
Mitchell Plant	A two unit, 1,560 MW coal-fired power plant located in Moundsville, West Virginia. The plant is jointly owned by KPCo and WPCo.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.

Term	Meaning
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.
NMRD	New Mexico Renewable Development, LLC.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NOLC	Net Operating Loss Carryforward.
NO_x	Nitrogen oxide.
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.
PLR	Private Letter Ruling.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSA	Purchase and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTC	Production Tax Credit.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, jointly owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated VIE for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.

Term	Meaning
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Transition Funding	AEP Texas Central Transition Funding III LLC, a wholly-owned subsidiary of AEP Texas and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
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 economic impact of increased global trade tensions including the conflicts in Ukraine and the Middle East, and the adoption or expansion of economic sanctions or trade restrictions.
- Inflationary or deflationary interest rate trends.
- Volatility and disruptions in financial markets precipitated by any cause, including failure to make progress on federal budget or debt ceiling matters or instability in the banking industry; particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- The availability and cost of funds to finance working capital and capital needs, particularly (a) if expected sources of capital such as proceeds from the sale of assets, subsidiaries and tax credits and anticipated securitizations do not materialize or do not materialize at the level anticipated, and (b) during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Decreased demand for electricity.
- Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.
- Limitations or restrictions on the amounts and types of insurance available to cover losses that might arise in connection with natural disasters or operations.
- The cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and SNF.
- The availability of fuel and necessary generation capacity and the performance of generation plants.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to transition from fossil generation and the ability to build or acquire renewable generation, transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms, including favorable tax treatment, cost caps imposed by regulators and other operational commitments to regulatory commissions and customers for renewable generation projects, and to recover all related costs.
- The impact of pandemics and any associated disruption of AEP’s business operations due to impacts on economic or market conditions, costs of compliance with potential government regulations, electricity usage, supply chain issues, customers, service providers, vendors and suppliers.
- New legislation, litigation or government regulation, including changes to tax laws and regulations, oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or PM and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- The impact of federal tax legislation on results of operations, financial condition, cash flows or credit ratings.
- The risks before, during and after generation of electricity associated with the fuels used or the by-products and wastes of such fuels, including coal ash and SNF.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation or regulatory proceedings or investigations.
- The ability to efficiently manage operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas.

- The impact of changing expectations and demands of customers, regulators, investors and stakeholders, including focus on environmental, social and governance concerns.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars and military conflicts, the effects of terrorism (including increased security costs), embargoes, wildfires, cybersecurity threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information, except as required by law. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2023 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

AEP Consolidated Earnings Attributable to Common Shareholders

First Quarter of 2024 Compared to First Quarter of 2023

Earnings Attributable to AEP Common Shareholders increased from $397 million in 2023 to $1,003 million in 2024 primarily due to:

- A favorable impact from the receipt of PLRs in 2024 related to the treatment of NOLCs in retail rate making. See "NOLCs in Retail Jurisdictions - IRS PLRs" section below for additional information.
- Favorable rate proceedings in AEP's various jurisdictions.
- Investment in transmission assets, which resulted in higher revenues and income.
- An increase in sales volumes driven by favorable weather and increased load in the commercial customer class.
- A loss on the sale of the competitive contracted renewables portfolio in 2023.

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

Customer Demand

AEP's weather-normalized **retail sales** volumes for the first quarter of 2024 increased by 2.9% from the first quarter of 2023. Weather-normalized **residential sales** decreased by 0.7% in the first quarter of 2024 from the first quarter of 2023. Weather-normalized **commercial sales** increased by 10.5% in the first quarter of 2024 compared to the first quarter of 2023. The increase in commercial sales was primarily due to new data center loads and economic development. AEP's first quarter 2024 **industrial sales** volumes increased by 0.4% from the first quarter of 2023.

Supply Chain Disruption and Inflation

The Registrants have experienced certain supply chain disruptions driven by several factors including international tensions and the ramifications of regional conflict, increased demand due to the economic recovery from the pandemic, inflation, labor shortages in certain trades and shortages in the availability of certain raw materials. These supply chain disruptions have not had a material impact on the Registrants' net income, cash flows and financial condition, but have extended lead times for certain goods and services and have contributed to higher prices for fuel, materials, labor, equipment and other needed commodities. Management has implemented risk mitigation strategies in an attempt to mitigate the impacts of these supply chain disruptions.

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

2024 SIGNIFICANT DEVELOPMENTS AND TRANSACTIONS

NOLCs in Retail Jurisdictions - IRS PLRs

The Registrants have made rate filings with state commissions to transition to stand-alone treatment of NOLCs in retail rate making. The Registrants completed the transition in Tennessee, West Virginia and Virginia prior to 2024. In the most recent I&M, PSO and SWEPCo base rate cases, the companies filed to transition to stand-alone rate making which was contingent upon a supportive PLR from the IRS.

In April 2024, supportive PLRs for certain retail jurisdictions were received from the IRS, effective March 2024. The PLRs concluded NOLCs on a stand-alone rate making basis should be included in rate base and should also be included in the computation of Excess ADIT regulatory liabilities to be refunded to customers. Based on this conclusion, I&M, PSO and SWEPCo recognized regulatory assets related to revenue requirement amounts to be collected from customers, reduced Excess ADIT regulatory liabilities and recorded favorable impacts to net income in the first quarter of 2024 as shown in the table below:

Registrant	Increase in Pretax Income from the Recognition of Regulatory Assets	Reduction in Income Tax Expense (a)	Increase in Net Income
		(in millions)	
I&M	$ 20.2	$ 49.5	$ 69.7
PSO	12.1	44.7	56.8
SWEPCo	35.4	101.1	136.5
AEP Total	$ 67.7	$ 195.3	$ 263.0

(a) Primarily relates to a $224 million remeasurement of Excess ADIT Regulatory Liabilities partially offset by $29 million of tax expense on favorable pretax income from the recognition of regulatory assets.

Planned Sale of AEP Energy and AEP Onsite Partners

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

AEP Energy

In October 2022, AEP initiated a strategic evaluation for its ownership in AEP Energy, a wholly-owned retail energy supplier that offers electricity and natural gas on a price risk managed basis to residential, commercial and industrial customers. AEP Energy provides various energy solutions in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy had approximately 954,000 customer accounts as of March 31, 2024. In April 2023, AEP management completed the strategic evaluation of AEP Energy and initiated a sale process. The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in mid-2024. At conclusion of this process, AEP may decide to retain its interest in AEP Energy. Depending on the outcome of the sales process, it could reduce future net income and impact financial condition.

AEP Onsite Partners

In April 2023, AEP initiated a sales process for its ownership in AEP Onsite Partners. AEP OnSite Partners targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions. As of March 31, 2024, AEP OnSite Partners owned projects located in 21 states, including approximately 102 MWs of installed solar capacity and three solar projects under construction totaling approximately 9 MWs. As of March 31, 2024, the net book value of these assets was $349 million. The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in mid-2024. At conclusion of this process, AEP may decide to retain its interest in AEP Onsite Partners.

AEP Onsite Partners also owned a 50% interest in NMRD. The NMRD portfolio consisted of 9 operating solar projects totaling 185 MWs and 6 projects totaling 440 MWs in development. In December 2023, AEP and the joint owner signed an agreement to sell NMRD to a nonaffiliated third party and the sale was completed in February 2024. AEP received cash proceeds of approximately $107 million, net of taxes and transaction costs. The transaction did not have a material impact on net income or financial condition. See the "Disposition of NMRD" section of Note 6 for additional information.

Voluntary Severance Program

In April 2024, management announced a voluntary severance program designed to achieve a reduction in the size of AEP's workforce and help offset increasing Other Operation and Maintenance expenses due to inflation in order to keep electricity costs affordable for customers. Approximately 7,400 of AEP's 16,800 employees are eligible to participate in the program. Participating employees will receive two weeks of base pay for every year of service with a minimum of four weeks and a maximum of 52 weeks of base pay. Management expects to record a charge to expense in the second quarter of 2024 related to this voluntary severance program. At this time, management is unable to predict the impact on net income, cash flows and financial condition, but the amount may be material.

Federal Tax Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022, or IRA.

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits. In 2023, AEP, on behalf of PSO, SWEPCo and AEP Energy Supply, LLC, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $174 million with $102 million received in 2023, $62 million received in the first quarter of 2024 and the remaining $10 million was received in April 2024. AEP expects to continue to explore the ability to efficiently monetize its tax credits through third party transferability agreements.

I&M's Cook Plant qualifies for the transferable Nuclear PTC, which is available for tax years beginning in 2024 through 2032. The Nuclear PTC is calculated based on electricity generated and sold to third-parties and is subject to a "reduction amount" as the facility's gross receipts increase above a certain threshold. Due to lack of guidance and uncertainty surrounding the computation of gross receipts, AEP and I&M are unable to estimate the amount of the Nuclear PTCs earned as of March 31, 2024 and have not included any Nuclear PTCs in the annualized effective tax rate for the first quarter of 2024. See Note 11 - Income Taxes for additional information.

New Generation to Support Reliability

The growth of AEP's regulated generation portfolio reflects the company's commitment to meet customer's energy and capacity needs while balancing cost and reliability.

Significant Approved Generation Filings

AEP has received regulatory approvals from various state regulatory commissions to acquire approximately 2,811 MWs of owned renewable generation facilities, totaling approximately $6.6 billion, in addition to 612 MWs of renewable purchase power agreements, as included in the following table:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	2024-2026	PPA	439
APCo	Wind	2025-2026	Owned	347
I&M	Solar	2025	PPA	100
I&M	Solar	2027	Owned	469
PSO (a)	Solar	2025-2026	Owned	443
PSO (a)	Wind	2025-2026	Owned	553
SWEPCo (b)	Solar	2025-2027	Owned/PPA	273
SWEPCo (b)(c)	Wind	2024-2025	Owned	799
Total Approved Renewable Projects				3,423

(a) PSO issued notices to proceed for the construction of two wind facilities and one solar facility for a combined total capacity of 477 MWs that will have an approximate cost of $1 billion. These facilities reflect the first of the approved projects contemplated within PSO's 996 MWs of total new renewable generation.

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

(c) SWEPCo issued notice to proceed for the construction of a 200 MW capacity wind facility that will have an approximate cost of $425 million. This facility is the first of the approved projects contemplated within SWEPCo's 799 MWs of total new renewable wind generation.

In addition to the generation projects in the table above, AEP enters into Capacity Purchase Agreements (CPA) to satisfy operating companies capacity reserve margins to serve customers. The following table includes CPA amounts currently under contract, by year:

	APCo	I&M		KPCo		PSO		SWEPCo		WPCo
	Coal	Coal	Natural Gas	Coal	Natural Gas	Natural Gas	Wind	Natural Gas	Wind	Coal
Delivery Start Year	(in MWs)									
2024	34	230	314	56	80	1,114	29	425	57	56
2025	—	—	440	—	85	1,150	29	350	135	—
2026	—	—	—	—	—	980	86	200	78	—
2027	—	—	210	—	—	260	86	—	78	—
2028	—	—	210	—	—	260	—	—	—	—
After 2028	—	—	1,050	—	—	780	—	—	—	—

Significant Generation Requests for Proposal (RFP)

The table below includes RFPs recently issued for both owned and purchased power generation. Unless otherwise noted, RFPs issued are all-source solicitations for accredited capacity. Projects selected will be subject to regulatory approval.

Company	Issuance Date	Projected In-Service Dates	Generating Capacity
			(in MWs)
I&M (a)	March 2023	2027	2,505
KPCo (b)	September 2023	2026/2027	1,300
PSO	November 2023	2027/2028	1,500
SWEPCo	January 2024	2028	2,100
Total Significant RFPs			7,405

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

Regulatory Matters - Utility Rates and Rate Proceedings

The Registrants are involved in rate cases and other proceedings with their regulatory commissions in order to establish fair and appropriate electric service rates to recover their costs and earn a fair return on their investments. Depending on the outcomes, these rate cases and proceedings can have a material impact on results of operations, cash flows and possibly financial condition. AEP is currently involved in the following key proceedings.

The following tables show the Registrants' completed and pending base rate case proceedings in 2024. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

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

(a) See "2022 Oklahoma Base Rate Case" section of Note 4 in the 2023 Annual Report for additional information.
(b) See "2020-2022 Virginia Triennial Review" section of Note 4 in the 2023 Annual Report for additional information.
(c) See "2023 Kentucky Base Rate and Securitization Case" section of Note 4 in the 2023 Annual Report for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Annual Base Revenue Increase Request	Requested ROE
			(in millions)	
I&M	Indiana	August 2023	$ 116.0	10.5%
I&M	Michigan	September 2023	34.0	10.5%
PSO	Oklahoma	January 2024	218.0	10.8%
AEP Texas	Texas	February 2024	164.0	10.6%
APCo	Virginia	March 2024	95.0	10.8%

Other Significant Regulatory Matters

Ohio ESP Filings

In January 2023, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments, proposed new riders and the continuation and modification of certain existing riders, including the DIR, effective June 2024 through May 2030. The proposal includes a return on common equity of 10.65% on capital costs for certain riders. In June 2023, intervenors filed testimony opposing OPCo's plan for various new riders and modifications to existing riders, including the DIR. In September 2023, OPCo and certain intervenors filed a settlement agreement with the PUCO addressing the ESP application. The settlement included a four year term from June 2024 through May 2028, an ROE of 9.7% and continuation of a number of riders including the DIR subject to revenue caps. In April 2024, the PUCO issued an order approving the settlement agreement.

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. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCT. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was remanded to the PUCT for future proceedings. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

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

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. In January 2024, the PUCT established a procedural schedule for the remand proceeding. On March 1, 2024, SWEPCo filed supplemental direct testimony with the PUCT in response to the December 2023 preliminary order. On March 8, 2024, intervenors and the PUCT staff filed a motion with the PUCT to strike portions of SWEPCo's October 2023 direct testimony and March 2024 supplemental direct testimony. On March 19, 2024, the ALJ granted portions of the motion which included removal of testimony supporting SWEPCo's position that refunds are not appropriate. On March 28, 2024, SWEPCo filed an appeal of the ALJ decision with the PUCT. A decision by the PUCT on the appeal is expected in the second quarter of 2024. In April 2024, intervenors and PUCT staff submitted testimony recommending customer refunds through December 2023 ranging from $149 million to $197 million, including carrying charges, with refund periods ranging from 18 months to 48 months. A hearing is scheduled for May 2024. Although SWEPCo does not currently believe any refunds are probable of occurring, SWEPCo estimates it could be required to make customer refunds, including interest, ranging from $0 to $200 million related to revenues collected from February 2013 through March 2024.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

The Registrants transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements, and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2024, 2023, 2022 and 2021 by $52 million, $60 million, $69 million and $78 million, respectively.

In January 2024, the FERC issued two orders granting formal challenges by certain unaffiliated customers related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEP made filings with the FERC which request that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing, and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. The Registrants have not yet been directed to make cash refunds related to the 2024, 2023 or 2022 rate years.

As a result of the January 2024 FERC orders, the Registrants' balance sheets reflect a liability for the probable refund of all NOLC revenues included in transmission formula rates for years 2024, 2023, 2022 and 2021, with interest. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets, with the exception of amounts expected to be refunded within one year which are reflected in Other Current Liabilities. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms.

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW (650 MW net maximum capacity) pulverized coal ultra-supercritical generating unit in Arkansas, which was placed in-service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MWs/477 MWs) of the Turk Plant and operates the facility. As of March 31, 2024, the net book value of the Turk Plant was $1.4 billion, before cost of removal including CWIP and inventory.

Approximately 20% of SWEPCo's portion of the Turk Plant output is currently not subject to cost-based rate recovery in Arkansas. This portion of the plant's output is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under retail cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-approved rates. In November 2022, SWEPCo filed a Certificate of Public Convenience and Necessity with the APSC for approval to operate the Turk Plant to serve Arkansas customers and recover the associated costs through a cost recovery rider. Cost-based recovery of the Turk Plant would aid SWEPCo's near-term capacity needs and support compliance with SPP's 2023 increased capacity planning reserve margin requirements. In April 2023, intervenors filed testimony recommending the APSC deny the Certificate of Public Convenience and Necessity on the basis that the Turk Plant is not the least cost alternative. In March 2024, the APSC issued an order denying SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers. As a result of the APSC's March 2024 order, SWEPCo recorded a $32 million favorable impact to net income as a result of the reduction to the regulatory liability related to the merchant portion of Turk Plant Excess ADIT.

Kentucky Securitization Case

In January 2024, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets balances as of the time securitization bonds are issued and concluding that costs requested for recovery through securitization were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement, and issuance that were not reflected in KPCo's proposal. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the second half of 2024, subject to market conditions. As of March 31, 2024, regulatory asset balances expected to be recovered through securitization total $476 million and include: (a) $288 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $46 million of deferred purchased power expenses, (d) $62 million of under-recovered purchased power rider costs and (e) $1 million of deferred issuance-related expenses including KPSC advisor expenses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. In February 2024, KPCo filed a motion to strike and exclude intervenor testimony. In March 2024, the KPSC denied KPCo's February 2024 motion. A hearing is expected in 2024. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce net income and cash flows and impact financial condition.

KPCo Fuel Adjustment Clause (FAC) Review

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

Deferred Fuel Costs

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

Company	Jurisdiction	Expected/Authorized Recovery Period	As of March 31, 2024		As of December 31, 2023	Increase/ (Decrease)
					(in millions)	
APCo	Virginia	2025	$ 221.1	(a)	$ 254.4	$ (33.3)
APCo	West Virginia	2034	164.1	(b)	162.2	1.9
PSO	Oklahoma	2024	155.8	(c)	118.3	37.5
SWEPCo	Texas	2035	81.0	(d)	80.9	0.1
WPCo	West Virginia	2034	206.2	(b)	181.3	24.9
		Total	$ 828.2		$ 797.1	$ 31.1

(a) In September 2023, APCo submitted a filing with the Virginia SCC requesting to extend the previously authorized recovery period through October 2024 to October 2025. Interim Virginia FAC rates were implemented in November 2023. The Virginia SCC staff analyzed APCo's fuel procurement activities and concluded the procurement practices were reasonable and prudent and have recommended no disallowances. In March 2024, the Hearing Examiner issued a report on APCo's Virginia fuel update filing that did not recommend any disallowances. The Hearing Examiner's report recommended leaving the review of APCo fuel costs for 2021 and 2022 open for further evaluation. An order from the Virginia SCC is expected in the first half of 2024.

(b) In January 2024, the WVPSC issued a final order which approved the recovery of $321 million ($174 million attributable to APCo and $147 million attributable to WPCo) of under-recovered ENEC regulatory assets as of February 28, 2023 over 10 years beginning September 1, 2024. In February 2024, the Companies filed briefs with the West Virginia Supreme Court to initiate an appeal of this order.

(c) In September 2022, the Director of the Public Utility Division of the OCC approved a Fuel Cost Adjustment rate designed to collect a $402 million deferred fuel balance through December 2024. In April 2024, the OCC issued an order confirming the prudency of the 2022 fuel and purchased power expenses.

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

Ohio House Bill 6 (HB 6)

In July 2019, HB 6, which offered incentives for power-generating facilities with zero or reduced carbon emissions, was signed into law by the Ohio Governor. HB 6 terminated energy efficiency programs as of December 31, 2020, including OPCo's shared savings revenues of $26 million annually and phased out renewable mandates after 2026. HB 6 also provided for continued recovery of existing renewable energy contracts on a bypassable basis through 2032 and included a provision for continued recovery of OVEC costs through 2030 which is allocated to all electric distribution utility customers in Ohio on a non-bypassable basis. OPCo's Inter-Company Power Agreement for OVEC terminates in June 2040. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of the Speaker of the Ohio House of Representatives, Larry Householder, four other individuals, and Generation Now, an entity registered as a 501(c)(4) social welfare organization, in connection with an alleged racketeering conspiracy involving the adoption of HB 6. Certain defendants in that case had previously plead guilty and, in March 2023, a federal jury convicted Larry Householder and another individual of participating in the racketeering conspiracy. In 2021, four AEP shareholders filed derivative actions purporting to assert claims on behalf of AEP against certain AEP officers and directors. See "Litigation Related to Ohio House Bill 6" section of Litigation below for additional information.

In March 2021, the Governor of Ohio signed legislation that, among other things, repealed the payments to the nonaffiliated owner of Ohio's nuclear power plants that were previously authorized under HB 6. The new legislation, House Bill 128, went into effect in May 2021 and leaves unchanged other provisions of HB 6 regarding energy efficiency programs, recovery of renewable energy costs and recovery of OVEC costs. To the extent that the law changes or OPCo (a) is unable to recover the costs of renewable energy contracts on a bypassable basis by the end of 2032, (b) is unable to recover costs of OVEC after 2030 or (c) incurs significant costs associated with the derivative actions, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

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

Litigation Related to Ohio House Bill 6 (HB 6)

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

In August 2020, an AEP shareholder filed a putative class action lawsuit in the U. S. District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. In December 2021, the district court issued an opinion and order dismissing the securities litigation complaint with prejudice, determining that the complaint failed to plead any actionable misrepresentations or omissions. The plaintiffs did not appeal the ruling.

In January 2021, an AEP shareholder filed a derivative action in the U.S. District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The court entered a scheduling order in the New York state court derivative action staying the case other than with respect to briefing the motion to dismiss. AEP filed substantive and forum-based motions to dismiss in April 2022. In June 2022, the Ohio state court entered an order continuing the stays of that case until the final resolution of the consolidated derivative actions pending in Ohio federal district court. In September 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiff subsequently filed a notice of appeal with the New York appellate court. In January 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York. The two derivative actions pending in federal district court in Ohio have been consolidated and the plaintiffs in the consolidated action filed an amended complaint. AEP filed a motion to dismiss the amended complaint and subsequently filed a brief in opposition to the New York plaintiffs' motion to intervene in the consolidated action in Ohio. In March 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. In April 2023, one of the plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Sixth Circuit of the Ohio federal district court order dismissing the consolidated action and denying the intervention. The defendants will continue to defend against the claims. Management does not believe the range of potential losses that is reasonably possible of occurring will have a material impact on results of operations, cash flows or financial condition.

In March 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter was directed to the Board of Directors of AEP (AEP Board) and contained factual allegations involving HB 6 that were generally consistent with those in the derivative litigation filed in state and federal court. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect. In April 2023, AEP received a litigation demand from counsel representing the purported AEP shareholder who filed the dismissed derivative action in New York state court and unsuccessfully tried to intervene in the consolidated derivative actions in Ohio federal court. The litigation demand letter is directed to the AEP Board and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by certain current and former directors and officers, and that AEP commence a civil action for breaches of fiduciary duty and related claims against any individuals who allegedly harmed AEP. The AEP Board considered the 2023 litigation demand letter and formed a committee of the Board (the "Demand Review Committee") to investigate, review, monitor and analyze the allegations in the letter and make a recommendation to the AEP Board regarding a reasonable and appropriate response to the same. The AEP Board will act in response to the letter as appropriate. Management does not believe the range of potential losses that is reasonably possible of occurring will have a material impact on results of operations, cash flows or financial condition.

In May 2021, AEP received a subpoena from the SEC's Division of Enforcement seeking various documents, including documents relating to the passage of HB 6 and documents relating to AEP's policies and financial processes and controls. In August 2022, AEP received a second subpoena from the SEC seeking various additional documents relating to its ongoing investigation. AEP is cooperating fully with the SEC's investigation, which has included taking testimony from certain individuals and inquiries regarding Empowering Ohio's Economy, Inc., which is a 501(c)(4) social welfare organization, and related disclosures. The SEC staff has advanced its discussions with certain parties involved in the investigation, including AEP, concerning the staff's intentions regarding potential claims under the securities laws. AEP and the SEC are engaged in discussions about a possible resolution of the SEC's investigation and potential claims under the securities laws. Any resolution or filed claims, the outcome of which cannot be predicted, may subject AEP to civil penalties and other remedial measures. Discussions are continuing and management does not believe the range of potential losses that is reasonably possible of occurring as a result of this investigation, or possible resolution thereof, will have a material impact on results of operations, cash flows or financial condition.

Claims for Indemnification Made by Owners of the Gavin Power Station

In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow a CCR surface impoundment at the Gavin Power Station to continue to receive CCR and non-CCR waste streams after April 11, 2021 until May 4, 2023 (the Gavin Denial). As part of the Gavin Denial, the Federal EPA made several assertions related to the CCR Rule (see "CCR Rule" section below for additional information), including an assertion that the closure of the 300 acre unlined fly ash reservoir (FAR) is noncompliant with the CCR Rule in multiple respects. The Gavin Power Station was formerly owned and operated by AEP and was sold to Gavin Power LLC and Lightstone Generation LLC in 2017. Pursuant to the PSA, AEP maintained responsibility to complete closure of the FAR in accordance with the closure plan approved by the Ohio EPA which was completed in July 2021. The PSA contains indemnification provisions, pursuant to which the owners of the Gavin Power Station have notified AEP they believe they are entitled to indemnification for any damages that may result from these claims, including any future enforcement or litigation resulting from any determinations of noncompliance by the Federal EPA with various aspects of the CCR Rule consistent with the Gavin Denial. The owners of the Gavin Power Station have also sought indemnification for landowner claims for property damage allegedly caused by modifications to the FAR. Management does not believe that the owners of the Gavin Power Station have any valid claim for indemnity or otherwise against AEP under the PSA. In addition, Gavin Power LLC, several AEP subsidiaries, and other parties have filed Petitions for Review of the Gavin Denial with the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to determine a range of potential losses that is reasonably possible of occurring. In January 2024, Gavin Power LLC also filed a complaint with the United States District Court for the Southern District of Ohio, alleging various violations of the Administrative Procedure Act and asserting that the Federal EPA, through its prior inaction, has waived and is estopped from raising certain objections raised in the Gavin Denial. Management cannot predict the outcome of that litigation.

Litigation Regarding Justice Thermal Coal Contract

In December 2023, APCo filed a suit in the Franklin County Ohio Court of Common Pleas seeking a declaratory judgment confirming APCo's right to terminate a long-term coal contract with Justice Thermal LLC ("Justice Thermal") based on Justice Thermal's failure to perform under the contract. APCo terminated that contract in January 2024, and in April 2024 APCo filed an amended complaint seeking a declaration that the termination was proper and also seeking damages for Justice Thermal's breach of contract. Justice Thermal filed an answer and counterclaim in April 2024, contesting the validity of the contract termination and asserting counterclaims. Justice Thermal's counterclaims allege that APCo breached the contract, assert a claim for fraud relating to APCo's alleged fabrication of coal sample analyses, and seek damages. APCo will continue to pursue its claims and defend against the counterclaims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. Management is engaged in the development of possible future requirements including the items discussed below.

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

Impact of Environmental Compliance on the Generating Fleet

The rules and environmental control requirements discussed below will have a material impact on AEP's operations. As of March 31, 2024, AEP owned generating capacity of approximately 23,200 MWs, of which approximately 10,700 MWs were coal-fired. In April 2024, the Federal EPA announced four major new rules directed at fossil-fuel electric generation facilities. Management continues to evaluate the impacts of these rules on the plans for the future of AEP's generating fleet, in particular, the economic feasibility of making the requisite environmental investments on AEP's fossil generation fleet. AEP continues to refine the cost estimates of complying with these rules to identify the best alternative for ensuring compliance with all of the rules while meeting AEP's obligations to provide reliable and affordable electricity.

The costs of complying with new rules may also change based on: (a) potential state rules that impose additional more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) actual performance of the pollution control technologies installed, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity, and (g) other factors.

Clean Air Act Requirements

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

National Ambient Air Quality Standards

The Federal EPA periodically reviews and revises the NAAQS for criteria pollutants under the CAA. Revisions tend to increase the stringency of the standards, which in turn may require AEP to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. In February 2024, the Federal EPA finalized a new more stringent annual primary $PM_{2.5}$ standard.

Areas with air quality that does not meet the new standard will be designated by the Federal EPA as "nonattainment," which will trigger an obligation for states to revise their SIPs to include additional requirements, resulting in further emission reductions to ensure that the new standard will be met. Areas around some of AEP's generating facilities may be deemed nonattainment, which may require those facilities to install additional pollution controls or to implement operational constraints. The nonattainment designations by the Federal EPA and the subsequent SIP revisions by the affected states will take some time to complete; therefore, management cannot reasonably estimate the impact on AEP's operations, cash flows, net income or financial condition.

Regional Haze

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

The Federal EPA disapproved portions of the Texas regional haze SIP and finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_X regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations. Legal challenges to these various rulemakings are pending in both the U.S. Court of Appeals for the Fifth Circuit and the U.S. Court of Appeals for the District of Columbia Circuit. Management cannot predict the outcome of that litigation, although management supports the intrastate trading program as a compliance alternative to source-specific controls and has intervened in the litigation in support of the Federal EPA.

Cross-State Air Pollution Rule

CSAPR is a regional trading program that the Federal EPA began implementing in 2015, which was originally designed to address interstate transport of emissions that contribute significantly to non-attainment and interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ NAAQS in downwind states. CSAPR relies on SO_2 and NO_X allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted basis. The Federal EPA has revised, or updated, the CSAPR trading programs several times since they were established.

In January 2021, the Federal EPA finalized a revised CSAPR, which substantially reduced the ozone season NO_X budgets for several states, including states where AEP operates, beginning in ozone season 2021. AEP has been able to meet the requirements of the revised rule over the first few years of implementation, and is evaluating its compliance options for later years, when the budgets are further reduced.

In addition, in February 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states, including Texas, addressing the 2015 Ozone NAAQS. The Federal EPA disapproved interstate transport SIPs submitted by additional states soon thereafter. Disapproval of the SIPs provided the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapproved. In August 2023, a FIP went into effect that further revised the ozone season NO_X budgets under the existing CSAPR program in states to which the FIP applies. Several states and industry parties initiated legal challenges to the Federal EPA's SIP disapprovals, and at the request of those parties, the courts have stayed SIP disapprovals for several states, including some states in which AEP operates. The Federal EPA has issued interim rules staying the FIP for states where the courts have stayed the underlying SIP disapprovals for the period while the judicial stays of the SIP disapprovals remain in place. The disapproval of SIPs and implementation of FIPs continues to be subject to extensive litigation. Management will continue to monitor the outcome of this litigation and the development of SIPs for any potential impact to operations.

Climate Change, CO_2 Regulation and Energy Policy

In April 2024, the Administrator of the Federal EPA signed new greenhouse gas standards and guidelines for new and existing fossil-fuel fired sources. The rule relies on carbon capture and sequestration and natural gas co-firing as means to reduce CO_2 emissions from coal fired plants and carbon capture and sequestration to reduce CO_2 emissions from new gas turbines. The Federal EPA deferred the finalization of standards for existing gas turbines until later in 2024. AEP is in the early stages of evaluating and identifying the best strategy for complying with this and other new rules, discussed below, while ensuring the adequacy of resources to meet customer needs. AEP is also evaluating potential legal challenges to the rule.

Even in the absence of federal regulatory requirements to reduce CO_2 emissions, AEP has already 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. Certain states where AEP has generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions.

AEP routinely submits IRPs in various regulatory jurisdictions to address future generation and capacity needs. These IRPs take into account economics, customer demand, grid reliability and resilience, regulations and RTO capacity requirements. The objective of the IRPs is to recommend future generation and capacity resources that provide the most cost-efficient and reliable power to customers. In October 2022, AEP announced new intermediate and long-term CO_2 emission reduction goals. AEP adjusted its near-term CO_2 emission reduction target from a 2000 baseline to a 2005 baseline, upgraded its 80% reduction by 2030 target to include full Scope 1 emissions and accelerated its net-zero goal by five years to 2045 for Scope 1 and Scope 2 emissions. AEP's total Scope 1 GHG estimated emissions in 2023 were approximately 44.5 million metric tons, a 67% reduction according to the GHG Protocol, which excludes emission reductions that result from assets that have been sold, or a 71% reduction from AEP's 2005 Scope 1 GHG emissions (inclusive of emission reductions that result from plants that have been sold).

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

Excessive costs to comply with environmental regulations have led to the announcement of early plant closures across the country. The Federal EPA's new GHG rules and the suite of other new rules announced simultaneously and directed at the fossil-fuel fired electric utility industry, see discussion of other rules below, and could force AEP to close additional coal-fired generation facilities earlier than their estimated useful life. If AEP is unable to recover the costs of its investments, it would reduce future net income and cash flows and impact financial condition.

MATS Rule

In April 2024, the Federal EPA issued a revised MATS rule for power plants. The rule includes a more stringent standard for emissions of filterable PM for coal-fired electric generating units, as well as a new mercury standard for lignite-fired electric generating units. The rule also requires the installation and operation of continuous emissions monitors for PM. Management is evaluating the impacts of the rule, but does not anticipate any significant challenges complying with the rule.

CCR Rule

The Federal EPA's CCR rule regulates the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The original rule applied to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers. With revisions announced in April 2024, the scope of the rule has expanded significantly, to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units").

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

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

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

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

Under the second option for obtaining an extension of the April 11, 2021 deadline to cease operation of unlined impoundments, a generating facility may continue operating its existing impoundments without developing alternative CCR disposal, provided the facility commits to cease combustion of coal by a date certain. Under this option, a generating facility had until October 17, 2023 to cease coal-fired operations and to close CCR storage ponds 40 acres or less in size, or through October 17, 2028 for facilities with CCR storage ponds greater than 40 acres in size. Pursuant to this option, AEP informed the Federal EPA of its intent to retire the Pirkey Plant and cease using coal at the Welsh Plant. In March 2023, the Pirkey Plant was retired. To date, the Federal EPA has not taken any action on the pending extension request for the Welsh Plant.

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units"). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. AEP is evaluating the applicability of the rule to current and former plant sites and is working to develop estimates of compliance costs, which are expected to be material, including costs to upgrade or close and replace legacy CCR surface impoundments and to conduct any required remedial actions including removal of coal ash.

Closure and post-closure estimated costs for facilities subject to the original CCR Rule have been included in ARO in accordance with the requirements in the Federal EPA's original CCR rule. Material ARO revisions will be necessary to address the expanded scope of facilities subject to the revised rule. Additional material ARO revisions may 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.

AEP would need to seek cost recovery through regulated rates, including proposing new regulatory mechanisms for cost recovery where existing mechanisms are not applicable, for which regulatory approval cannot be assured. The rule could have a material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover any additional costs of compliance. Management is also evaluating potential legal challenges to the revised rule.

Clean Water Act Regulations

The Federal EPA's ELG rule for generating facilities establishes limits for FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. A revision to the ELG rule, published in October 2020, established additional options for reusing and discharging small volumes of bottom ash transport water, provided an exception for retiring units and extended the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. Management has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water. For affected facilities that must install additional technologies to meet the ELG rule limits, permit modifications were filed in January 2021 that reflect the outcome of that assessment. AEP continues to work with state agencies to finalize permit terms and conditions. Other facilities opted to file Notices of Planned Participation (NOPP), pursuant to which the facilities are not required to install additional controls to meet ELG limits provided they make commitments to cease coal combustion by a date certain. In April 2024, the Federal EPA finalized further revisions to the ELG rule that establish a zero liquid discharge standard for FGD wastewater, bottom ash transport water, and managed combustion residual leachate, as well as more stringent discharge limits for unmanaged combustion residual leachate. The revised rule provides a new compliance alternative that would avoid the need to install zero liquid discharge systems for facilities that comply with the 2020 rule's control technology requirements and commit to retire by 2024. Management is evaluating the compliance alternatives in the rule, taking into consideration the requirements of the other new rules and their combined impacts to operations. Management is also evaluating potential legal challenges to the rule.

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

Impact of Environmental Regulation on Coal-Fired Generation

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

The table below summarizes the net book value, as of March 31, 2024, 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	$ 96.7	$ 20.7	2026	(c)	$ 15.1
SWEPCo	Pirkey Plant	—	121.0 (d)	2023	(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	335.6	58.1	2028 (f)	(g)	39.2

(a) Net book value, including CWIP excluding cost of removal and materials and supplies.
(b) These amounts represent the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Represents Arkansas and Texas jurisdictional share.
(e) As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. The Texas share of the Pirkey Plant will be addressed in SWEPCo's next base rate case. See the "Coal-Fired Generation Plants" section of Note 4 for additional information.
(f) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028. Management is evaluating a potential conversion to natural gas after 2028 for both units.
(g) Welsh Plant, Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Welsh Plant, Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

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

RESULTS OF OPERATIONS

AEP's Reportable Segments

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

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

The remainder of AEP's activities are presented as Corporate and Other, which is not considered a reportable segment. See Note 8 - Business Segments for additional information on AEP's segments.

The following discussion of AEP's results of operations by operating segment provides a comparison of Earnings Attributable to AEP Common Shareholders for the three months ended March 31, 2024 as compared to the three months ended March 31, 2023. For AEP's Vertically Integrated Utilities and Transmission and Distribution Utilities segment and subsidiary registrants within these segments, the results include revenues from rate rider mechanisms designed to recover fuel, purchased power and other recoverable expenses such that the revenues and expenses associated with these items generally offset and do not affect Earnings Attributable to AEP Common Shareholders. For additional information regarding the financial results for the three months ended March 31, 2024 and 2023 see the discussions of Results of Operations by Subsidiary Registrant.

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

	Three Months Ended March 31,	
	2024	**2023**
	(in millions)	
Vertically Integrated Utilities	$ 560.8	$ 261.0
Transmission and Distribution Utilities	150.3	125.7
AEP Transmission Holdco	208.7	181.5
Generation & Marketing	137.6	(157.7)
Corporate and Other	(54.3)	(13.5)
Earnings Attributable to AEP Common Shareholders	$ 1,003.1	$ 397.0

Three Months Ended March 31, 2024

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 2,947.9	$ 1,490.2	$ 497.3	$ 563.5
Fuel, Purchased Electricity and Other	999.1	305.3	—	372.6
Other Operation and Maintenance	885.3	519.2	37.1	31.5
Depreciation and Amortization	453.6	222.5	108.1	8.2
Taxes Other Than Income Taxes	139.7	190.8	75.0	0.2
Operating Income	470.2	252.4	277.1	151.0
Other Income	5.1	0.5	2.4	11.0
Allowance for Equity Funds Used During Construction	11.7	14.1	17.8	—
Non-Service Cost Components of Net Periodic Benefit Cost	25.9	11.1	1.0	5.8
Interest Expense	(157.2)	(96.2)	(56.9)	(6.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	355.7	181.9	241.4	161.8
Income Tax Expense (Benefit)	(206.2)	31.5	54.3	25.1
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.4	(0.1)	22.7	0.9
Net Income	562.3	150.3	209.8	137.6
Net Income Attributable to Noncontrolling Interests	1.5	—	1.1	—
Earnings Attributable to AEP Common Shareholders	$ 560.8	$ 150.3	$ 208.7	$ 137.6

Three Months Ended March 31, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 2,857.8	$ 1,464.2	$ 455.5	$ 327.0
Fuel, Purchased Electricity and Other	976.2	392.7	—	382.3
Other Operation and Maintenance	832.2	491.9	36.7	43.0
Loss on the Sale of the Competitive Contracted Renewable Portfolio	—	—	—	112.0
Depreciation and Amortization	473.5	186.2	97.5	18.2
Taxes Other Than Income Taxes	132.4	178.8	76.8	2.8
Operating Income (Loss)	443.5	214.6	244.5	(231.3)
Other Income	7.2	0.5	1.9	9.0
Allowance for Equity Funds Used During Construction	5.8	9.1	16.4	—
Non-Service Cost Components of Net Periodic Benefit Cost	31.8	14.0	1.6	6.6
Interest Expense	(172.9)	(88.1)	(47.2)	(24.3)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings	315.4	150.1	217.2	(240.0)
Income Tax Expense (Benefit)	53.5	24.4	52.3	(78.1)
Equity Earnings of Unconsolidated Subsidiary	0.3	—	17.5	5.5
Net Income (Loss)	262.2	125.7	182.4	(156.4)
Net Income Attributable to Noncontrolling Interests	1.2	—	0.9	1.3
Earnings (Loss) Attributable to AEP Common Shareholders	$ 261.0	$ 125.7	$ 181.5	$ (157.7)

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	8,560	8,099
Commercial	5,769	5,372
Industrial	8,252	8,295
Miscellaneous	538	521
Total Retail	23,119	22,287
Wholesale (a)	3,763	3,260
Total KWhs	26,882	25,547

(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, 2024	2023
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,221	1,131
Normal – Heating (b)	1,605	1,608
Actual – Cooling (c)	1	5
Normal – Cooling (b)	4	4
Western Region		
Actual – Heating (a)	738	637
Normal – Heating (b)	876	881
Actual – Cooling (c)	55	58
Normal – Cooling (b)	30	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.

Reconciliation of First Quarter of 2023 to First Quarter of 2024
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

First Quarter of 2023	$	261.0
Changes in Revenues:		
Retail Revenues		56.2
Off-system Sales		3.7
Transmission Revenues		10.2
Other Revenues		20.0
Total Change in Revenues		90.1
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(22.9)
Other Operation and Maintenance		(53.1)
Depreciation and Amortization		19.9
Taxes Other Than Income Taxes		(7.3)
Other Income		(2.1)
Allowance for Equity Funds Used During Construction		5.9
Non-Service Cost Components of Net Periodic Pension Cost		(5.9)
Interest Expense		15.7
Total Change in Expenses and Other		(49.8)
Income Tax Expense		259.7
Equity Earnings of Unconsolidated Subsidiary		0.1
Net Income Attributable to Noncontrolling Interests		(0.3)
First Quarter of 2024	$	560.8

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

- **Retail Revenues** increased $56 million primarily due to the following:
  - A $46 million increase in rider revenues at APCo.
  - A $24 million increase in weather-related usage primarily in the residential class driven by an 11% increase in heating degree days.
  - A $19 million increase in base rate and rider revenues at PSO.
  - A $15 million increase in rider revenues at KPCo.
  - A $5 million increase in rider revenues at I&M.

  These increases were partially offset by:
  - A $45 million decrease in fuel revenues primarily due to decreases at PSO and SWEPCo, partially offset by increases at APCo and I&M.
  - A $13 million decrease due to a regulatory provision for refund at I&M.
- **Transmission Revenues** increased $10 million primarily due to:
  - A $6 million increase primarily due to lower PJM rates in 2023 for certain point-to-point transmission service resulting from a December 2022 FERC approved settlement agreement.
  - A $3 million increase due to increased transmission investment.
- **Other Revenues** increased $20 million primarily due to pole attachment revenue at APCo, increases in associated business development at PSO and SWEPCo and increased affiliated rent revenue at PSO.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $23 million primarily due to increases at APCo and I&M, partially offset by decreases at PSO and SWEPCo.
- **Other Operation and Maintenance expenses** increased $53 million primarily due to:
  - A $39 million increase in transmission services.
  - A $14 million increase primarily due to a disallowance recorded at SWEPCo on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.
- **Depreciation and Amortization** decreased $20 million primarily due to a $17 million decrease at I&M due to the deferral of Excess ADIT as a result of the PLR received regarding the treatment of stand alone NOLCs and the timing of refunds to customers under rate rider mechanisms.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to an increase in the Virginia state minimum tax liability at APCo and increased property taxes driven by additional investments and higher tax rates at I&M.
- **Allowance for Equity Funds Used During Construction** increased $6 million primarily due to higher CWIP and AFUDC equity rates.
- **Non-Service Cost Components of Net Periodic Pension Cost** increased $6 million primarily due to a decrease in the expected return on asset assumption, an increase in loss amortization, changes in prior service credit amortization, partially offset by lower loss amortization resulting from favorable asset returns during 2023 and lower interest costs due to lower interest rates.
- **Interest Expense** decreased $16 million primarily due to:
  - A $49 million decrease due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.

  This decrease was partially offset by:
  - A $17 million increase due to higher long-term debt balances and interest rates.
  - A $14 million increase due to a decrease in carrying charges at SWEPCo on storm-related regulatory assets due to a prior year settlement agreement in Louisiana.
- **Income Tax Expense** decreased $260 million primarily due to the following:
  - A $212 million decrease due to a reduction in Excess ADIT regulatory liabilities at I&M, PSO, and SWEPCo as a result of the PLR received regarding the treatment of stand alone NOLCs.
  - A $32 million decrease due to a reduction in Excess ADIT regulatory liabilities as a result of the APSC's denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers.
  - A $15 million decrease due to an increase in PTCs.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	6,280	6,266
Commercial	7,991	6,744
Industrial	6,812	6,526
Miscellaneous	180	168
Total Retail (a)	21,263	19,704
Wholesale (b)	590	453
Total KWhs	21,853	20,157

(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, 2024	2023
	(in degree days)	
Eastern Region		
Actual – Heating (a)	1,463	1,344
Normal – Heating (b)	1,871	1,891
Actual – Cooling (c)	—	—
Normal – Cooling (b)	3	3
Western Region		
Actual – Heating (a)	161	141
Normal – Heating (b)	195	194
Actual – Cooling (d)	146	271
Normal – Cooling (b)	137	127

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

Reconciliation of First Quarter of 2023 to First Quarter of 2024
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

First Quarter of 2023	$	125.7
Changes in Revenues:		
Retail Revenues		3.3
Off-system Sales		(3.6)
Transmission Revenues		12.9
Other Revenues		13.4
Total Change in Revenues		26.0
Changes in Expenses and Other:		
Purchased Electricity for Resale		134.0
Purchased Electricity from AEP Affiliates		(46.6)
Other Operation and Maintenance		(27.3)
Depreciation and Amortization		(36.3)
Taxes Other Than Income Taxes		(12.0)
Allowance for Equity Funds Used During Construction		5.0
Non-Service Cost Components of Net Periodic Benefit Cost		(2.9)
Interest Expense		(8.1)
Total Change in Expenses and Other		5.8
Income Tax Expense		(7.1)
Equity Earnings of Unconsolidated Subsidiary		(0.1)
First Quarter of 2024	$	150.3

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

- **Retail Revenues** increased $3 million primarily due to the following:
  - A $105 million increase in rider revenues.
  - A $20 million increase in weather-normalized revenues primarily in the residential and commercial classes in Texas.
  - A $16 million increase in weather-related usage driven by a 9% increase in heating degree days in Ohio.

  These increases were partially offset by:
  - A $122 million decrease due to lower customer participation in OPCo's SSO, partially offset by higher prices.
  - A $9 million decrease in weather-normalized revenues in the residential and industrial classes, partially offset by the commercial class in Ohio.
  - An $8 million decrease in weather-related usage primarily due to a 46% decrease in cooling degree days in Texas.
- **Transmission Revenues** increased $13 million primarily due to interim rate increases driven by increased transmission investments in Texas.
- **Other Revenues** increased $13 million primarily due to the following:
  - A $10 million increase due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.
  - A $6 million increase in refundable sales of renewable energy credits in Ohio.

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

- **Purchased Electricity for Resale** expenses decreased $134 million primarily due to the following:
  - A $177 million decrease due to lower auction volumes driven by lower customer participation in OPCo's SSO, partially offset by higher prices.

  This decrease was partially offset by:
  - A $30 million decrease in deferrals of recoverable OVEC costs.
- **Purchased Electricity from AEP Affiliates** expenses increased $47 million primarily due to increased purchases in OPCo's SSO auction.
- **Other Operation and Maintenance** expenses increased $27 million primarily due to the following:
  - A $27 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses in Ohio.
  - A $16 million increase in distribution expenses primarily related to recoverable storm restoration costs and recoverable vegetation management expenses in Ohio.

  These increases were partially offset by:
  - A $5 million decrease in distribution-related expenses in Texas.
  - A $3 million decrease in recoverable transmission expenses in Texas.
- **Depreciation and Amortization** expenses increased $36 million primarily due to a higher depreciable base and an increase in recoverable rider depreciable expenses in Ohio.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to property taxes as a result of increased transmission and distribution investment and higher tax rates in Ohio.
- **Interest Expense** increased $8 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $7 million primarily due to an increase in pretax book income in Texas.

AEP TRANSMISSION HOLDCO

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	March 31, 2024	March 31, 2023
	(in millions)	
Plant in Service	$ 14,740.7	$ 13,376.3
Construction Work in Progress	1,980.2	1,959.1
Accumulated Depreciation and Amortization	1,405.8	1,128.2
Total Transmission Property, Net	$ 15,315.1	$ 14,207.2

Reconciliation of First Quarter of 2023 to First Quarter of 2024
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

First Quarter of 2023	$ 181.5
Changes in Transmission Revenues:	
Transmission Revenues	41.8
Total Change in Transmission Revenues	41.8
Changes in Expenses and Other:	
Other Operation and Maintenance	(0.4)
Depreciation and Amortization	(10.6)
Taxes Other Than Income Taxes	1.8
Interest and Investment Income	0.5
Allowance for Equity Funds Used During Construction	1.4
Non-Service Cost Components of Net Periodic Pension Cost	(0.6)
Interest Expense	(9.7)
Total Change in Expenses and Other	(17.6)
Income Tax Expense	(2.0)
Equity Earnings of Unconsolidated Subsidiary	5.2
Net Income Attributable to Noncontrolling Interests	(0.2)
First Quarter of 2024	$ 208.7

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

- **Transmission Revenues** increased $42 million primarily due to continued investment in transmission assets.

Expenses and Other and Equity Earnings of Unconsolidated Subsidiary changed between years as follows:

- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances and interest rates.
- **Equity Earnings of Unconsolidated Subsidiary** increased $5 million primarily due to higher pretax equity earnings for ETT.

GENERATION & MARKETING

Reconciliation of First Quarter of 2023 to First Quarter of 2024
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

First Quarter of 2023	$	(157.7)
Changes in Revenues:		
Merchant Generation		(5.0)
Renewable Generation		(20.8)
Retail, Trading and Marketing		262.3
Total Change in Revenues		236.5
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		9.7
Other Operation and Maintenance		11.5
Loss on the Sale of the Competitive Contracted Renewables Portfolio		112.0
Depreciation and Amortization		10.0
Taxes Other Than Income Taxes		2.6
Interest and Investment Income		2.0
Non-Service Cost Components of Net Periodic Benefit Cost		(0.8)
Interest Expense		18.3
Total Change in Expenses and Other		165.3
Income Tax Benefit		(103.2)
Equity Earnings of Unconsolidated Subsidiaries		(4.6)
Net Loss Attributable to Noncontrolling Interests		1.3
First Quarter of 2024	$	137.6

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

- **Merchant Generation** decreased $5 million primarily due to lower market prices in 2024.
- **Renewable Generation** decreased $21 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Retail, Trading and Marketing** increased $262 million primarily due to a $145 million unrealized loss on economic hedge activity in 2023 and $91 million unrealized hedging gains in 2024 driven by changes in commodity prices.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $10 million primarily due to a reduction in energy costs in 2024.
- **Other Operation and Maintenance** expenses decreased $12 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Loss on the Sale of the Competitive Contracted Renewables Portfolio** increased $112 million due to the pretax loss on the sale in 2023.
- **Depreciation and Amortization** decreased $10 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Interest Expense** decreased $18 million primarily due to lower advances from affiliates.

- **Income Tax Benefit** decreased $103 million primarily due to:
  - An $83 million decrease due to increased pretax book income.
  - A $19 million decrease due to an decrease in PTCs.
  - A $9 million decrease due to the amortization of deferred ITCs from the sale of the competitive contracted renewables portfolio in 2023.

  These decreases were partially offset by:
  - A $12 million increase due to the amortization of deferred ITCs from the sale of NMRD.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $5 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.

CORPORATE AND OTHER

First Quarter of 2024 Compared to First Quarter of 2023

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $14 million in 2023 to a loss of $54 million in 2024 primarily due to:

- A $23 million decrease in interest income, primarily due to lower advances to affiliates.
- A $14 million increase in interest expense due to higher interest rates and an increase in long-term debt balances.
- A $10 million increase in corporate expenses, primarily due to prior-year adjustments driven by the termination of the sale of the Kentucky operations.

These decreases in earnings were partially offset by a $5 million decrease in Income Tax Expense due to the following:

- A $15 million decrease due to a decrease in pretax book income.
- A $10 million decrease due to an increase in PTCs.

These decreases in Income Tax Expense were partially offset by:

- A $12 million increase due to the impact of the termination of the sale of the Kentucky operations in 2023.
- An $8 million increase due to a decrease in amortization of Excess ADIT.

AEP CONSOLIDATED INCOME TAXES

First Quarter of 2024 Compared to First Quarter of 2023

Income Tax Expense decreased $152 million primarily due to:

- A $224 million decrease due to a reduction in Excess ADIT regulatory liabilities at I&M, PSO, and SWEPCo as a result of the PLRs received regarding the treatment of stand alone NOLCs in retail rate making.
- A $32 million decrease due to the reversal of a regulatory liability related to the merchant portion of Turk Plant Excess ADIT as a result of the APSC's March 2024 denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers.

These decreases were partially offset by:

- A $95 million increase due to an increase in pretax book income.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	March 31, 2024		December 31, 2023	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 39,835.9	57.4 %	$ 40,143.2	58.8 %
Short-term Debt	3,737.6	5.4	2,830.2	4.2
Total Debt	43,573.5	62.8	42,973.4	63.0
AEP Common Equity	25,803.3	37.2	25,246.7	37.0
Noncontrolling Interests	40.4	—	39.2	—
Total Debt and Equity Capitalization	$ 69,417.2	100.0 %	$ 68,259.3	100.0 %

AEP's ratio of debt-to-total capital decreased slightly from 63.0% to 62.8% as of December 31, 2023 and March 31, 2024, respectively, primarily due to an increase in earnings in 2024, partially offset by an increase in debt to support distribution, transmission and renewable investment growth in addition to working capital needs.

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, 2024, AEP had $6 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. AEP and its utilities finance its operations with commercial paper and other variable rate instruments that are subject to fluctuations in interest rates. To the extent that there is an increase in interest rates, it could reduce future net income and cash flows and impact financial condition.

Market volatility and reduced liquidity in the financial markets could affect AEP's ability to raise capital on reasonable terms to fund capital needs, including construction costs and refinancing maturing indebtedness. AEP is also monitoring the current bank environment and any impacts thereof. AEP was not materially impacted by these conditions during the three months ended March 31, 2024.

AEP continues to address the cash flow implications of increased fuel and purchased power costs, see "Deferred Fuel Costs" section of Executive Overview for additional information.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of March 31, 2024, available liquidity was approximately $3.4 billion as illustrated in the table below:

	Amount	Maturity (a)
Commercial Paper Backup:	(in millions)	
Revolving Credit Facility	$ 5,000.0	March 2029
Revolving Credit Facility	1,000.0	March 2027
Cash and Cash Equivalents	230.7	
Total Liquidity Sources	6,230.7	
Less: AEP Commercial Paper Outstanding	2,832.2	
Net Available Liquidity	$ 3,398.5	

(a) In March 2024, AEP increased its $4 billion Revolving Credit Facility to $5 billion and extended the maturity date from March 2027 to March 2029. Also, in March 2024, AEP extended the maturity date of its $1 billion Revolving Credit Facility from March 2025 to March 2027.

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 2024 was $2.9 billion. The weighted-average interest rate for AEP's commercial paper during 2024 was 5.62%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2024 was $247 million with maturities ranging from April 2024 to March 2025.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables and expires in September 2025. As of March 31, 2024, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of March 31, 2024, this contractually-defined percentage was 60.2%. 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 $100 million, would cause an event of default under these credit agreements. This condition also applies, at the more restrictive level of $50 million of debt outstanding, in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

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

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

ATM Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, up to an aggregate of $1.7 billion of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. There were no issuances under the ATM program for the three months ended March 31, 2024. As of March 31, 2024, approximately $1.7 billion of equity is available for issuance under the ATM offering program. See Note 12 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.88 per share in April 2024. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 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, 2024	Three Months Ended March 31, 2023
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 379.0	$ 556.5
Net Cash Flows from Operating Activities	1,442.2	717.8
Net Cash Flows Used for Investing Activities	(1,669.3)	(2,245.2)
Net Cash Flows from Financing Activities	129.9	1,364.4
Net Decrease in Cash and Cash Equivalents	(97.2)	(163.0)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 281.8	$ 393.5

Operating Activities

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(in millions)	
Net Income	$ 1,005.7	$ 400.4
Non-Cash Adjustments to Net Income (a)	630.2	924.2
Mark-to-Market of Risk Management Contracts	40.9	(82.0)
Property Taxes	(89.2)	(101.6)
Deferred Fuel Over/Under-Recovery, Net	43.4	128.0
Change in Other Noncurrent Assets	(74.5)	(96.0)
Change in Other Noncurrent Liabilities	61.8	(58.7)
Change in Certain Components of Working Capital	(176.1)	(396.5)
Net Cash Flows from Operating Activities	$ 1,442.2	$ 717.8

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, Loss on the Sale of the Competitive Contracted Renewables Portfolio and AFUDC.

Net Cash Flows from Operating Activities increased by $724 million primarily due to the following:

- A $311 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $220 million increase in cash from the Change in Certain Components of Working Capital. The increase is primarily due to the timing of accounts payable, decreases in fuel, material and supplies driven by coal inventory on hand and proceeds received from the sale of transferable tax credits. These increases were partially offset by the timing of accounts receivable collections.
- A $142 million increase in cash from Changes in Other Noncurrent Assets and Liabilities. This increase is primarily due to changes in regulatory assets and liabilities driven by timing differences between collections from and refunds to customers under rate rider mechanisms.
- A $123 million increase primarily due to an increase in collateral held associated with risk management contracts driven by a change in commodity prices.

These increases in cash were partially offset by:

- An $85 million decrease in cash primarily due to the timing of fuel and purchase power revenues and expenses.

Investing Activities

	Three Months Ended March 31,	
	2024	2023
	(in millions)	
Construction Expenditures	$ (1,761.7)	$ (2,090.1)
Acquisitions of Nuclear Fuel	(33.7)	(1.7)
Acquisitions of Renewable Energy Facilities	—	(145.7)
Proceeds from Sale of Equity Method Investment	114.0	—
Other	12.1	(7.7)
Net Cash Flows Used for Investing Activities	$ (1,669.3)	$ (2,245.2)

Net Cash Flows Used for Investing Activities decreased by $576 million primarily due to the following:

- A $328 million decrease in Construction Expenditures, primarily due to decreases in Transmission and Distribution Utilities of $140 million, AEP Transmission Holdco of $76 million and Vertically Integrated Utilities of $74 million.
- A $146 million decrease due to the 2023 acquisition of the Rock Falls Wind Facility. See "Rock Falls Wind Facility" section of Note 6 for additional information.
- A $114 million increase in Proceeds from Sale of Equity Method Investment. See "Disposition of NMRD" section of Note 6 for additional information.

Financing Activities

	Three Months Ended March 31,	
	2024	2023
	(in millions)	
Issuance of Common Stock	$ 40.6	$ 41.1
Issuance/Retirement of Debt, Net	605.1	1,837.7
Dividends Paid on Common Stock	(466.9)	(431.8)
Other	(48.9)	(82.6)
Net Cash Flows from Financing Activities	$ 129.9	$ 1,364.4

Net Cash Flows from Financing Activities decreased by $1.2 billion primarily due to the following:

- A $2 billion decrease in issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $643 million increase in retirements of long-term debt. See Note 12 - Financing Activities for additional information.

These decreases in cash were partially offset by:

- A $1.4 billion 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, 2024 through April 30, 2024, the date that the first quarter 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.5 billion of capital expenditures in 2024. For the four year period, 2025 through 2028, management forecasts capital expenditures of $35 billion. The expenditures are generally for transmission, generation, distribution, regulated renewables and required environmental investment to comply with the Federal EPA rules. Estimated capital expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, supply chain issues, weather, legal reviews, inflation and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations, proceeds from the strategic sale of assets and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. For complete information of forecasted capital expenditures, see "Budgeted Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2023 Annual Report.

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2023 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 2023 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 and SEC rulemaking activity.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards and SEC rulemaking activity.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

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

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

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

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2023:

MTM Derivative Contract Net Assets (Liabilities)

Three Months Ended March 31, 2024

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
	(in millions)			
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of December 31, 2023	$ 16.9	$ (51.0)	$ 92.4	$ 58.3
(Gain)/Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(26.9)	2.3	39.1	14.5
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	1.3	1.3
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(25.8)	—	23.1	(2.7)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(5.1)	8.0	—	2.9
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of March 31, 2024	$ (40.9)	$ (40.7)	$ 155.9	74.3
Commodity Cash Flow Hedge Contracts				110.7
Interest Rate Cash Flow Hedge Contracts				6.6
Fair Value Hedge Contracts				(114.8)
Collateral Deposits				(73.6)
Total MTM Derivative Contract Net Assets as of March 31, 2024				$ 3.2

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

See Note 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, 2024, credit exposure net of collateral to sub investment grade counterparties was approximately 7.7%, 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, 2024, 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	$ 595.2	$ 86.4	$ 508.8	3	$ 278.9
Split Rating	17.8	—	17.8	1	17.8
No External Ratings:					
Internal Investment Grade	21.0	—	21.0	3	13.2
Internal Noninvestment Grade	102.2	56.4	45.8	2	40.5
Total as of March 31, 2024	$ 736.2	$ 142.8	$ 593.4		

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

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of March 31, 2024, 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, 2024				Twelve Months Ended December 31, 2023			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 1.7	$ 0.4	$ 0.1	$ 0.2	$ 0.9	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Three Months Ended March 31, 2024				Twelve Months Ended December 31, 2023			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 14.6	$ 98.6	$ 25.0	$ 11.9	$ 17.7	$ 32.7	$ 16.4	$ 6.1

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

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

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. Prior to 2022, interest rates remained at low levels and the Federal Reserve maintained the federal funds target range at 0.0% to 0.25% for much of 2021. During 2022 and 2023, the Federal Reserve approved 11 rate increases for a cumulative total of 5.25% increase. AEP has outstanding short and long-term debt which is subject to variable rates. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the three months ended March 31, 2024 and 2023, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $40 million and $43 million, respectively.

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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
REVENUES		
Vertically Integrated Utilities	$ 2,901.2	$ 2,816.3
Transmission and Distribution Utilities	1,483.2	1,455.3
Generation & Marketing	515.9	326.9
Other Revenues	125.4	92.4
TOTAL REVENUES	5,025.7	4,690.9
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,575.8	1,706.4
Other Operation	762.3	680.0
Maintenance	317.5	317.3
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	112.0
Depreciation and Amortization	787.1	775.5
Taxes Other Than Income Taxes	410.4	394.9
TOTAL EXPENSES	3,853.1	3,986.1
OPERATING INCOME	1,172.6	704.8
Other Income (Expense):		
Other Income	13.6	14.7
Allowance for Equity Funds Used During Construction	43.6	31.3
Non-Service Cost Components of Net Periodic Benefit Cost	45.1	55.5
Interest Expense	(435.6)	(415.7)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	839.3	390.6
Income Tax Expense (Benefit)	(141.9)	10.4
Equity Earnings of Unconsolidated Subsidiaries	24.5	20.2
NET INCOME	1,005.7	400.4
Net Income Attributable to Noncontrolling Interests	2.6	3.4
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,003.1	$ 397.0
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	526,552,036	514,176,648
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.91	$ 0.77
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	527,596,395	515,598,090
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.90	$ 0.77

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	**2023**
Net Income	$ 1,005.7	$ 400.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(1.6) and $(40.5) in 2024 and 2023, Respectively	(6.2)	(152.4)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(4.3) in 2024 and 2023, Respectively	(0.6)	(16.1)
Reclassifications of KPCo Pension and OPEB Regulatory Assets, Net of Tax of $0 and $4.4 in 2024 and 2023, Respectively	—	16.7
TOTAL OTHER COMPREHENSIVE LOSS	(6.8)	(151.8)
TOTAL COMPREHENSIVE INCOME	998.9	248.6
Total Comprehensive Income Attributable To Noncontrolling Interests	2.6	3.4
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 996.3	$ 245.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2024 and 2023
(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, 2022	525.1	$ 3,413.1	$ 8,051.0	$ 12,345.6	$ 83.7	$ 229.0	$ 24,122.4
Issuance of Common Stock	0.8	5.1	36.0				41.1
Common Stock Dividends				(428.8) (a)		(3.0)	(431.8)
Other Changes in Equity			(12.7)			0.2	(12.5)
Net Income				397.0		3.4	400.4
Other Comprehensive Loss					(151.8)		(151.8)
TOTAL EQUITY – MARCH 31, 2023	525.9	$ 3,418.2	$ 8,074.3	$ 12,313.8	$ (68.1)	$ 229.6	$ 23,967.8
TOTAL EQUITY – DECEMBER 31, 2023	527.4	$ 3,427.9	$ 9,073.9	$ 12,800.4	$ (55.5)	$ 39.2	$ 25,285.9
Issuance of Common Stock	0.8	5.4	35.2				40.6
Common Stock Dividends				(465.5) (b)		(1.4)	(466.9)
Other Changes in Equity			(14.8)				(14.8)
Net Income				1,003.1		2.6	1,005.7
Other Comprehensive Loss					(6.8)		(6.8)
TOTAL EQUITY – MARCH 31, 2024	528.2	$ 3,433.3	$ 9,094.3	$ 13,338.0	$ (62.3)	$ 40.4	$ 25,843.7

(a) Cash dividends declared per AEP common share were $0.83.
(b) Cash dividends declared per AEP common share were $0.88.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 230.7	$ 330.1
Restricted Cash (March 31, 2024 and December 31, 2023 Amounts Include $51.1 and $48.9, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)	51.1	48.9
Other Temporary Investments (March 31, 2024 and December 31, 2023 Amounts Include $206.1 and $205, Respectively, Related to EIS and Transource Energy)	217.0	214.3
Accounts Receivable:		
Customers	1,000.0	1,029.9
Accrued Unbilled Revenues	220.9	179.5
Pledged Accounts Receivable – AEP Credit	1,206.8	1,249.4
Miscellaneous	47.2	48.7
Allowance for Uncollectible Accounts	(59.6)	(60.1)
Total Accounts Receivable	2,415.3	2,447.4
Fuel	749.9	853.7
Materials and Supplies	1,020.4	1,025.8
Risk Management Assets	152.7	217.5
Accrued Tax Benefits	89.4	156.2
Regulatory Asset for Under-Recovered Fuel Costs	550.3	514.0
Prepayments and Other Current Assets	372.8	274.2
TOTAL CURRENT ASSETS	5,849.6	6,082.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,404.1	24,329.5
Transmission	36,253.1	35,934.1
Distribution	29,476.3	28,989.9
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	6,557.2	6,484.9
Construction Work in Progress	6,142.1	5,508.0
Total Property, Plant and Equipment	102,832.8	101,246.4
Accumulated Depreciation and Amortization	25,036.8	24,553.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	77,796.0	76,693.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,034.1	5,092.4
Securitized Assets	309.7	336.3
Spent Nuclear Fuel and Decommissioning Trusts	4,112.6	3,860.2
Goodwill	52.5	52.5
Long-term Risk Management Assets	314.4	321.2
Operating Lease Assets	603.0	620.2
Deferred Charges and Other Noncurrent Assets	3,672.7	3,625.7
TOTAL OTHER NONCURRENT ASSETS	14,099.0	13,908.5
TOTAL ASSETS	$ 97,744.6	$ 96,684.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2024 and December 31, 2023
(in millions, except per-share and share amounts)
(Unaudited)

		March 31, 2024		December 31, 2023
CURRENT LIABILITIES				
Accounts Payable	$	1,990.9	$	2,032.5
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit		900.0		888.0
Other Short-term Debt		2,837.6		1,942.2
Total Short-term Debt		3,737.6		2,830.2
Long-term Debt Due Within One Year (March 31, 2024 and December 31, 2023 Amounts Include $201.5 and $207.2, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)		1,198.6		2,490.5
Risk Management Liabilities		184.4		229.6
Customer Deposits		436.2		423.7
Accrued Taxes		1,675.6		1,800.1
Accrued Interest		507.3		410.2
Obligations Under Operating Leases		107.1		115.7
Other Current Liabilities		1,068.9		1,251.1
TOTAL CURRENT LIABILITIES		10,906.6		11,583.6
NONCURRENT LIABILITIES				
Long-term Debt (March 31, 2024 and December 31, 2023 Amounts Include $528.9 and $556.3, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)		38,637.3		37,652.7
Long-term Risk Management Liabilities		279.5		241.8
Deferred Income Taxes		9,662.1		9,415.7
Regulatory Liabilities and Deferred Investment Tax Credits		8,089.4		8,182.4
Asset Retirement Obligations		2,972.9		2,972.5
Employee Benefits and Pension Obligations		230.8		241.7
Obligations Under Operating Leases		509.3		519.4
Deferred Credits and Other Noncurrent Liabilities		561.4		545.8
TOTAL NONCURRENT LIABILITIES		60,942.7		59,772.0
TOTAL LIABILITIES		71,849.3		71,355.6
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards		51.6		42.5
TOTAL MEZZANINE EQUITY		51.6		42.5
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				

	2024	2023
Shares Authorized	600,000,000	600,000,000
Shares Issued	528,199,306	527,369,157

		March 31, 2024		December 31, 2023
(1,184,572 Shares were Held in Treasury as of March 31, 2024 and December 31, 2023, Respectively)		3,433.3		3,427.9
Paid-in Capital		9,094.3		9,073.9
Retained Earnings		13,338.0		12,800.4
Accumulated Other Comprehensive Income (Loss)		(62.3)		(55.5)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		25,803.3		25,246.7
Noncontrolling Interests		40.4		39.2
TOTAL EQUITY		25,843.7		25,285.9
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$	97,744.6	$	96,684.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
OPERATING ACTIVITIES		
Net Income	$ 1,005.7	$ 400.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	787.1	775.5
Deferred Income Taxes	(113.3)	68.0
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	112.0
Allowance for Equity Funds Used During Construction	(43.6)	(31.3)
Mark-to-Market of Risk Management Contracts	40.9	(82.0)
Property Taxes	(89.2)	(101.6)
Deferred Fuel Over/Under-Recovery, Net	43.4	128.0
Change in Other Noncurrent Assets	(74.5)	(96.0)
Change in Other Noncurrent Liabilities	61.8	(58.7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	34.9	348.4
Fuel, Materials and Supplies	104.3	(115.9)
Accounts Payable	(99.5)	(255.9)
Accrued Taxes, Net	(57.7)	(150.9)
Other Current Assets	(91.3)	(94.6)
Other Current Liabilities	(66.8)	(127.6)
Net Cash Flows from Operating Activities	1,442.2	717.8
INVESTING ACTIVITIES		
Construction Expenditures	(1,761.7)	(2,090.1)
Purchases of Investment Securities	(590.0)	(537.3)
Sales of Investment Securities	572.5	517.6
Acquisitions of Nuclear Fuel	(33.7)	(1.7)
Acquisitions of Renewable Energy Facilities	—	(145.7)
Proceeds from Sale of Equity Method Investment	114.0	—
Other Investing Activities	29.6	12.0
Net Cash Flows Used for Investing Activities	(1,669.3)	(2,245.2)
FINANCING ACTIVITIES		
Issuance of Common Stock	40.6	41.1
Issuance of Long-term Debt	859.9	2,847.3
Issuance of Short-term Debt with Original Maturities greater than 90 Days	376.6	97.4
Change in Short-term Debt with Original Maturities less than 90 Days, Net	840.9	(433.7)
Retirement of Long-term Debt	(1,162.2)	(519.5)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(310.1)	(153.8)
Principal Payments for Finance Lease Obligations	(17.0)	(26.8)
Dividends Paid on Common Stock	(466.9)	(431.8)
Other Financing Activities	(31.9)	(55.8)
Net Cash Flows from Financing Activities	129.9	1,364.4
Net Decrease in Cash and Cash Equivalents	(97.2)	(163.0)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	379.0	556.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 281.8	$ 393.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 368.3	$ 311.9
Net Cash Paid for Income Taxes	16.1	15.8
Cash Received from Sale of Transferable Tax Credits	(62.0)	—
Noncash Acquisitions Under Finance Leases	7.0	12.5
Construction Expenditures Included in Current Liabilities as of March 31,	837.0	1,076.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	2,529	2,532
Commercial	3,307	2,744
Industrial	3,273	3,108
Miscellaneous	151	138
Total Retail	9,260	8,522

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, 2024	2023
	(in degree days)	
Actual – Heating (a)	161	141
Normal – Heating (b)	195	194
Actual – Cooling (c)	146	271
Normal – Cooling (b)	137	127

(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.

AEP Texas Inc. and Subsidiaries
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Net Income
(in millions)

First Quarter of 2023	$	47.6
Changes in Revenues:		
Retail Revenues		28.8
Transmission Revenues		9.6
Other Revenues		(1.5)
Total Change in Revenues		36.9
Changes in Expenses and Other:		
Other Operation and Maintenance		8.4
Depreciation and Amortization		(5.7)
Taxes Other Than Income Taxes		3.5
Interest Income		0.1
Allowance for Equity Funds Used During Construction		2.3
Non-Service Cost Components of Net Periodic Benefit Cost		(1.1)
Interest Expense		(4.6)
Total Change in Expenses and Other		2.9
Income Tax Expense		(7.7)
First Quarter of 2024	$	79.7

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

- **Retail Revenues** increased $29 million primarily due to the following:
  - A $20 million increase in weather-normalized revenues primarily in the residential and commercial classes.
  - A $16 million increase in revenue from rate riders.

  These increases were partially offset by:
  - An $8 million decrease in weather-related usage primarily due to a 46% decrease in cooling degree days.
- **Transmission Revenues** increased $10 million due to interim rate increases driven by increased transmission investments.

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

- **Other Operation and Maintenance** expenses decreased $8 million primarily due to the following:
  - A $5 million decrease in distribution-related expenses.
  - A $3 million decrease in recoverable transmission expenses.
- **Depreciation and Amortization** expenses increased $6 million primarily due to a higher depreciable base.
- **Income Tax Expense** increased $8 million primarily due to an increase in pretax book income.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	**2023**
REVENUES		
Electric Transmission and Distribution	$ 463.0	$ 427.7
Sales to AEP Affiliates	1.3	1.2
Other Revenues	2.1	0.6
TOTAL REVENUES	466.4	429.5
EXPENSES		
Other Operation	140.8	146.9
Maintenance	22.1	24.4
Depreciation and Amortization	116.7	111.0
Taxes Other Than Income Taxes	40.0	43.5
TOTAL EXPENSES	319.6	325.8
OPERATING INCOME	146.8	103.7
Other Income (Expense):		
Interest Income	0.5	0.4
Allowance for Equity Funds Used During Construction	8.6	6.3
Non-Service Cost Components of Net Periodic Benefit Cost	3.7	4.8
Interest Expense	(61.5)	(56.9)
INCOME BEFORE INCOME TAX EXPENSE	98.1	58.3
Income Tax Expense	18.4	10.7
NET INCOME	$ 79.7	$ 47.6

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
Net Income	$ 79.7	$ 47.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $1.0 and $0 in 2024 and 2023, Respectively	3.9	—
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $(0.1) in 2024 and 2023, Respectively	—	(0.6)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	3.9	(0.6)
TOTAL COMPREHENSIVE INCOME	$ 83.6	$ 47.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 1,558.2	$ 2,354.7	$ (8.6)	$ 3,904.3
Capital Contribution from Parent	100.0			100.0
Net Income		47.6		47.6
Other Comprehensive Loss			(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2023	$ 1,658.2	$ 2,402.3	$ (9.2)	$ 4,051.3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 2,079.6	$ 2,725.1	$ (8.6)	$ 4,796.1
Net Income		79.7		79.7
Other Comprehensive Income			3.9	3.9
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2024	$ 2,079.6	$ 2,804.8	$ (4.7)	$ 4,879.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (March 31, 2024 and December 31, 2023 Amounts Include $42.7 and $34, Respectively, Related to Transition Funding and Restoration Funding)	42.7	34.0
Advances to Affiliates	7.0	7.1
Accounts Receivable:		
Customers	167.8	176.5
Affiliated Companies	21.2	23.8
Accrued Unbilled Revenues	85.2	82.3
Miscellaneous	0.7	0.8
Allowance for Uncollectible Accounts	(4.2)	(4.9)
Total Accounts Receivable	270.7	278.5
Materials and Supplies	194.0	190.4
Prepayments and Other Current Assets	10.6	10.0
TOTAL CURRENT ASSETS	525.1	520.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	6,896.6	6,812.6
Distribution	5,903.8	5,798.8
Other Property, Plant and Equipment	1,148.8	1,145.9
Construction Work in Progress	1,062.7	904.6
Total Property, Plant and Equipment	15,011.9	14,661.9
Accumulated Depreciation and Amortization	1,932.5	1,887.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	13,079.4	12,774.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	317.4	315.3
Securitized Assets (March 31, 2024 and December 31, 2023 Amounts Include $183.1 and $202.9, Respectively, Related to Transition Funding and Restoration Funding)	183.1	202.9
Deferred Charges and Other Noncurrent Assets	262.5	178.4
TOTAL OTHER NONCURRENT ASSETS	763.0	696.6
TOTAL ASSETS	$ 14,367.5	$ 13,990.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT LIABILITIES		
Advances from Affiliates	$ 267.9	$ 103.7
Accounts Payable:		
General	253.5	192.3
Affiliated Companies	30.9	27.7
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2024 and December 31, 2023 Amounts Include $96.2 and $95.9, Respectively, Related to Transition Funding and Restoration Funding)	96.2	96.0
Accrued Taxes	139.5	99.1
Accrued Interest (March 31, 2024 and December 31, 2023 Amounts Include $1.7 and $2, Respectively, Related to Transition Funding and Restoration Funding)	81.5	49.2
Obligations Under Operating Leases	24.7	28.7
Other Current Liabilities	147.7	152.7
TOTAL CURRENT LIABILITIES	1,041.9	749.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (March 31, 2024 and December 31, 2023 Amounts Include $114 and $125.9, Respectively, Related to Transition Funding and Restoration Funding)	5,782.5	5,793.8
Deferred Income Taxes	1,238.7	1,227.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,261.2	1,261.4
Obligations Under Operating Leases	50.1	50.9
Deferred Credits and Other Noncurrent Liabilities	113.4	111.3
TOTAL NONCURRENT LIABILITIES	8,445.9	8,445.2
TOTAL LIABILITIES	9,487.8	9,194.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	2,079.6	2,079.6
Retained Earnings	2,804.8	2,725.1
Accumulated Other Comprehensive Income (Loss)	(4.7)	(8.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,879.7	4,796.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 14,367.5	$ 13,990.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	2023
OPERATING ACTIVITIES		
Net Income	$ 79.7	$ 47.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	116.7	111.0
Deferred Income Taxes	6.6	6.4
Allowance for Equity Funds Used During Construction	(8.6)	(6.3)
Mark-to-Market of Risk Management Contracts	(0.2)	0.4
Property Taxes	(84.3)	(88.8)
Change in Other Noncurrent Assets	(17.2)	(18.3)
Change in Other Noncurrent Liabilities	3.0	(0.8)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	7.8	24.6
Materials and Supplies	(3.6)	(1.1)
Accounts Payable	11.6	3.6
Accrued Taxes, Net	42.6	44.5
Accrued Interest	32.3	23.9
Other Current Assets	1.4	0.9
Other Current Liabilities	(20.0)	(10.9)
Net Cash Flows from Operating Activities	167.8	136.7
INVESTING ACTIVITIES		
Construction Expenditures	(331.2)	(450.4)
Change in Advances to Affiliates, Net	0.1	0.1
Other Investing Activities	21.1	7.3
Net Cash Flows Used for Investing Activities	(310.0)	(443.0)
FINANCING ACTIVITIES		
Capital Contribution from Parent	—	100.0
Change in Advances from Affiliates, Net	164.2	354.3
Retirement of Long-term Debt – Nonaffiliated	(11.9)	(136.7)
Principal Payments for Finance Lease Obligations	(1.8)	(1.8)
Other Financing Activities	0.4	0.3
Net Cash Flows from Financing Activities	150.9	316.1
Net Increase in Cash, Cash Equivalents and Restricted Cash	8.7	9.8
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	34.1	32.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 42.8	$ 42.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 26.9	$ 31.6
Noncash Acquisitions Under Finance Leases	1.1	1.8
Construction Expenditures Included in Current Liabilities as of March 31,	158.3	177.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of March 31, 2024	As of March 31, 2023
	(in millions)	
Plant In Service	$ 14,335.9	$ 12,971.3
Construction Work in Progress	1,805.0	1,831.9
Accumulated Depreciation and Amortization	1,362.7	1,091.2
Total Transmission Property, Net	$ 14,778.2	$ 13,712.0

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Net Income
(in millions)

First Quarter of 2023	$ 162.7
Changes in Transmission Revenues:	
Transmission Revenues	41.2
Total Change in Transmission Revenues	41.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(1.3)
Depreciation and Amortization	(10.7)
Taxes Other Than Income Taxes	1.4
Interest Income	0.4
Allowance for Equity Funds Used During Construction	1.5
Interest Expense	(9.6)
Total Change in Expenses and Other	(18.3)
Income Tax Expense	(4.4)
First Quarter of 2024	$ 181.2

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

- **Transmission Revenues** increased $41 million primarily due to continued investment in transmission assets.

Expenses and Other changed between years as follows:

- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Interest Expense** increased $10 million due to higher long-term debt balances and interest rates.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
REVENUES		
Transmission Revenues	$ 98.4	$ 90.0
Sales to AEP Affiliates	389.4	357.4
Provision for Refund – Affiliated	(6.0)	(4.8)
Provision for Refund – Nonaffiliated	(1.4)	(1.0)
Other Revenues	2.4	—
TOTAL REVENUES	482.8	441.6
EXPENSES		
Other Operation	29.9	29.0
Maintenance	5.3	4.9
Depreciation and Amortization	105.9	95.2
Taxes Other Than Income Taxes	73.4	74.8
TOTAL EXPENSES	214.5	203.9
OPERATING INCOME	268.3	237.7
Other Income (Expense):		
Interest Income - Affiliated	1.9	1.5
Allowance for Equity Funds Used During Construction	17.9	16.4
Interest Expense	(54.8)	(45.2)
INCOME BEFORE INCOME TAX EXPENSE	233.3	210.4
Income Tax Expense	52.1	47.7
NET INCOME	$ 181.2	$ 162.7

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2022	$ 3,022.3	$ 2,850.7	$ 5,873.0
Capital Contribution from Member	25.0		25.0
Dividends Paid to Member		(55.0)	(55.0)
Net Income		162.7	162.7
TOTAL MEMBER'S EQUITY – MARCH 31, 2023	$ 3,047.3	$ 2,958.4	$ 6,005.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2023	$ 3,043.4	$ 3,289.9	$ 6,333.3
Capital Contribution from Member	25.0		25.0
Dividends Paid to Member		(40.0)	(40.0)
Net Income		181.2	181.2
TOTAL MEMBER'S EQUITY – MARCH 31, 2024	$ 3,068.4	$ 3,431.1	$ 6,499.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Advances to Affiliates	$ 298.0	$ 67.1
Accounts Receivable:		
Customers	80.6	82.2
Affiliated Companies	131.1	125.5
Total Accounts Receivable	211.7	207.7
Prepayments and Other Current Assets	11.2	4.0
TOTAL CURRENT ASSETS	520.9	278.8
TRANSMISSION PROPERTY		
Transmission Property	13,832.4	13,723.9
Other Property, Plant and Equipment	503.5	501.4
Construction Work in Progress	1,805.0	1,563.7
Total Transmission Property	16,140.9	15,789.0
Accumulated Depreciation and Amortization	1,362.7	1,291.3
TOTAL TRANSMISSION PROPERTY – NET	14,778.2	14,497.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	2.4	3.1
Deferred Property Taxes	250.1	286.4
Deferred Charges and Other Noncurrent Assets	7.4	6.5
TOTAL OTHER NONCURRENT ASSETS	259.9	296.0
TOTAL ASSETS	$ 15,559.0	$ 15,072.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
March 31, 2024 and December 31, 2023
(Unaudited)

	March 31, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 28.8	$ 174.3
Accounts Payable:		
General	289.6	274.7
Affiliated Companies	120.7	107.9
Long-term Debt Due Within One Year – Nonaffiliated	145.0	95.0
Accrued Taxes	505.3	568.6
Accrued Interest	56.8	39.6
Obligations Under Operating Leases	1.3	1.3
Other Current Liabilities	20.4	24.7
TOTAL CURRENT LIABILITIES	1,167.9	1,286.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,715.7	5,319.4
Deferred Income Taxes	1,175.4	1,147.7
Regulatory Liabilities	809.4	783.7
Obligations Under Operating Leases	1.2	1.4
Deferred Credits and Other Noncurrent Liabilities	189.9	200.9
TOTAL NONCURRENT LIABILITIES	7,891.6	7,453.1
TOTAL LIABILITIES	9,059.5	8,739.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	3,068.4	3,043.4
Retained Earnings	3,431.1	3,289.9
TOTAL MEMBER'S EQUITY	6,499.5	6,333.3
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 15,559.0	$ 15,072.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	2023
OPERATING ACTIVITIES		
Net Income	$ 181.2	$ 162.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	105.9	95.2
Deferred Income Taxes	25.0	20.6
Allowance for Equity Funds Used During Construction	(17.9)	(16.4)
Property Taxes	36.3	34.6
Change in Other Noncurrent Assets	(0.4)	0.9
Change in Other Noncurrent Liabilities	(6.1)	6.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4.0)	(12.5)
Materials and Supplies	—	(4.1)
Accounts Payable	5.4	41.0
Accrued Taxes, Net	(63.2)	(59.9)
Other Current Assets	1.0	1.0
Other Current Liabilities	10.8	29.6
Net Cash Flows from Operating Activities	274.0	299.3
INVESTING ACTIVITIES		
Construction Expenditures	(336.5)	(439.7)
Change in Advances to Affiliates, Net	(230.9)	(293.1)
Other Investing Activities	7.8	(0.8)
Net Cash Flows Used for Investing Activities	(559.6)	(733.6)
FINANCING ACTIVITIES		
Capital Contribution from Member	25.0	25.0
Issuance of Long-term Debt – Nonaffiliated	446.1	689.2
Change in Advances from Affiliates, Net	(145.5)	(224.9)
Dividends Paid to Member	(40.0)	(55.0)
Net Cash Flows from Financing Activities	285.6	434.3
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	$ 33.3	$ 16.2
Construction Expenditures Included in Current Liabilities as of March 31,	191.0	305.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	3,265	3,059
Commercial	1,475	1,403
Industrial	2,102	2,109
Miscellaneous	211	200
Total Retail	7,053	6,771
Wholesale	654	489
Total KWhs	7,707	7,260

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, 2024	2023
	(in degree days)	
Actual – Heating (a)	981	859
Normal – Heating (b)	1,310	1,321
Actual – Cooling (c)	2	8
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.

Appalachian Power Company and Subsidiaries
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Net Income
(in millions)

First Quarter of 2023	$	112.5
Changes in Revenues:		
Retail Revenues		90.4
Off-system Sales		(0.6)
Transmission Revenues		6.4
Other Revenues		9.1
Total Change in Revenues		105.3
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(57.1)
Other Operation and Maintenance		(27.7)
Depreciation and Amortization		(6.8)
Taxes Other Than Income Taxes		(4.2)
Interest Income		0.2
Allowance for Equity Funds Used During Construction		0.5
Non-Service Cost Components of Net Periodic Benefit Cost		(1.0)
Interest Expense		(2.8)
Total Change in Expenses and Other		(98.9)
Income Tax Expense		17.6
First Quarter of 2024	$	136.5

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

- **Retail Revenues** increased $90 million primarily due to the following:
  - A $46 million increase in rider revenues.
  - A $28 million increase in fuel revenue primarily due to authorized fuel rate increases in West Virginia.
  - A $17 million increase in weather-related usage driven by a 14% increase in heating degree days.
- **Transmission Revenues** increased $6 million primarily due to lower PJM rates in 2023 for certain point-to-point transmission services resulting from a December 2022 FERC approved settlement agreement.
- **Other Revenues** increased $9 million primarily due to pole attachment revenue.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $57 million primarily due to a $37 million increase in West Virginia fuel over-recovery and a $21 million increase in load.
- **Other Operation and Maintenance** expenses increased $28 million primarily due to the following:
  - A $23 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $10 million increase in distribution expenses primarily due to vegetation management expenses.

  These increases were partially offset by:
  - A $5 million decrease due to the January 2024 completion of regulatory asset amortization related to under-earnings during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $7 million primarily due to a higher depreciable base.
- **Income Tax Expense** decreased $18 million primarily due a $14 million increase in amortization of Excess ADIT.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	2023
REVENUES		
Electric Generation, Transmission and Distribution	$ 1,024.3	$ 914.5
Sales to AEP Affiliates	63.1	69.6
Other Revenues	5.6	3.6
TOTAL REVENUES	1,093.0	987.7
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	396.8	339.7
Other Operation	212.6	191.8
Maintenance	80.0	73.1
Depreciation and Amortization	149.8	143.0
Taxes Other Than Income Taxes	46.0	41.8
TOTAL EXPENSES	885.2	789.4
OPERATING INCOME	207.8	198.3
Other Income (Expense):		
Interest Income	0.8	0.6
Allowance for Equity Funds Used During Construction	2.9	2.4
Non-Service Cost Components of Net Periodic Benefit Cost	7.1	8.1
Interest Expense	(68.1)	(65.3)
INCOME BEFORE INCOME TAX EXPENSE	150.5	144.1
Income Tax Expense	14.0	31.6
NET INCOME	$ 136.5	$ 112.5

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
Net Income	$ 136.5	$ 112.5
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) in 2024 and 2023, Respectively	(0.2)	(0.2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.2) in 2024 and 2023, Respectively	(0.3)	(0.8)
TOTAL OTHER COMPREHENSIVE LOSS	(0.5)	(1.0)
TOTAL COMPREHENSIVE INCOME	$ 136.0	$ 111.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2022	$ 260.4	$ 1,828.7	$ 2,891.1	$ (4.8)	$ 4,975.4
Net Income			112.5		112.5
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2023	$ 260.4	$ 1,828.7	$ 3,003.6	$ (5.8)	$ 5,086.9
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2023	$ 260.4	$ 1,834.5	$ 3,185.5	$ (3.7)	$ 5,276.7
Capital Contribution from Parent		100.0			100.0
Net Income			136.5		136.5
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2024	$ 260.4	$ 1,934.5	$ 3,322.0	$ (4.2)	$ 5,512.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 7.6	$ 5.0
Restricted Cash for Securitized Funding	8.4	14.9
Advances to Affiliates	37.4	18.9
Accounts Receivable:		
Customers	191.1	170.3
Affiliated Companies	100.9	98.8
Accrued Unbilled Revenues	59.8	70.8
Miscellaneous	0.5	0.6
Allowance for Uncollectible Accounts	(2.3)	(2.0)
Total Accounts Receivable	350.0	338.5
Fuel	293.6	315.0
Materials and Supplies	139.8	148.4
Risk Management Assets	8.7	22.4
Regulatory Asset for Under-Recovered Fuel Costs	148.4	155.4
Prepayments and Other Current Assets	25.9	40.5
TOTAL CURRENT ASSETS	1,019.8	1,059.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	7,065.3	7,041.3
Transmission	4,747.5	4,711.8
Distribution	5,238.5	5,176.6
Other Property, Plant and Equipment	1,023.1	981.3
Construction Work in Progress	754.5	709.2
Total Property, Plant and Equipment	18,828.9	18,620.2
Accumulated Depreciation and Amortization	5,776.0	5,688.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	13,052.9	12,931.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,107.4	1,155.1
Securitized Assets	126.7	133.4
Employee Benefits and Pension Assets	176.3	171.7
Operating Lease Assets	72.0	73.7
Deferred Charges and Other Noncurrent Assets	197.3	187.5
TOTAL OTHER NONCURRENT ASSETS	1,679.7	1,721.4
TOTAL ASSETS	$ 15,752.4	$ 15,711.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2024 and December 31, 2023
(Unaudited)

	March 31, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 339.6
Accounts Payable:		
General	286.7	280.4
Affiliated Companies	107.0	121.3
Long-term Debt Due Within One Year – Nonaffiliated	153.3	538.8
Risk Management Liabilities	18.4	15.9
Customer Deposits	81.4	80.0
Accrued Taxes	146.9	117.6
Accrued Interest	83.0	58.9
Obligations Under Operating Leases	14.3	14.6
Other Current Liabilities	132.3	118.8
TOTAL CURRENT LIABILITIES	1,023.3	1,685.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,517.6	5,049.5
Deferred Income Taxes	2,019.8	2,011.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,082.5	1,081.9
Asset Retirement Obligations	441.5	442.5
Employee Benefits and Pension Obligations	31.6	32.8
Obligations Under Operating Leases	58.3	59.8
Deferred Credits and Other Noncurrent Liabilities	65.1	70.9
TOTAL NONCURRENT LIABILITIES	9,216.4	8,749.3
TOTAL LIABILITIES	10,239.7	10,435.2
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	1,934.5	1,834.5
Retained Earnings	3,322.0	3,185.5
Accumulated Other Comprehensive Income (Loss)	(4.2)	(3.7)
TOTAL COMMON SHAREHOLDER'S EQUITY	5,512.7	5,276.7
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 15,752.4	$ 15,711.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 136.5	$ 112.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	149.8	143.0
Deferred Income Taxes	(12.8)	10.3
Allowance for Equity Funds Used During Construction	(2.9)	(2.4)
Mark-to-Market of Risk Management Contracts	11.8	60.1
Deferred Fuel Over/Under-Recovery, Net	62.4	26.0
Change in Other Noncurrent Assets	3.9	(5.5)
Change in Other Noncurrent Liabilities	6.5	(33.0)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(10.6)	54.5
Fuel, Materials and Supplies	30.0	(59.3)
Margin Deposits	11.0	(11.1)
Accounts Payable	(24.7)	(156.1)
Accrued Taxes, Net	33.0	23.6
Other Current Assets	—	2.9
Other Current Liabilities	12.4	(1.2)
Net Cash Flows from Operating Activities	406.3	164.3
INVESTING ACTIVITIES		
Construction Expenditures	(236.0)	(287.4)
Change in Advances to Affiliates, Net	(18.5)	1.1
Other Investing Activities	3.6	1.5
Net Cash Flows Used for Investing Activities	(250.9)	(284.8)
FINANCING ACTIVITIES		
Capital Contribution from Parent	100.0	—
Issuance of Long-term Debt – Nonaffiliated	395.8	—
Change in Advances from Affiliates, Net	(339.6)	128.0
Retirement of Long-term Debt – Nonaffiliated	(313.4)	(13.0)
Principal Payments for Finance Lease Obligations	(2.2)	(2.0)
Other Financing Activities	0.1	0.2
Net Cash Flows from (Used for) Financing Activities	(159.3)	113.2
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(3.9)	(7.3)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	19.9	21.9
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 16.0	$ 14.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 41.5	$ 37.9
Noncash Acquisitions Under Finance Leases	0.3	0.6
Construction Expenditures Included in Current Liabilities as of March 31,	107.3	122.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

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MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	1,438	1,463
Commercial	1,275	1,189
Industrial	1,808	1,804
Miscellaneous	14	16
Total Retail	4,535	4,472
Wholesale	1,620	1,417
Total KWhs	6,155	5,889

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, 2024	2023
	(in degree days)	
Actual – Heating (a)	1,685	1,687
Normal – Heating (b)	2,181	2,182
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.

Indiana Michigan Power Company and Subsidiaries
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Net Income
(in millions)

First Quarter of 2023	$	102.8
Changes in Revenues:		
Retail Revenues		(1.9)
Off-system Sales		1.2
Transmission Revenues		4.5
Other Revenues		0.6
Total Change in Revenues		4.4
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		(23.4)
Purchased Electricity from AEP Affiliates		(16.4)
Other Operation and Maintenance		(2.3)
Depreciation and Amortization		16.9
Taxes Other Than Income Taxes		(3.8)
Other Income		2.6
Non-Service Cost Components of Net Periodic Benefit Cost		(1.3)
Interest Expense		7.0
Total Change in Expenses and Other		(20.7)
Income Tax Expense		58.5
First Quarter of 2024	$	145.0

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

- **Retail Revenues** decreased $2 million primarily due to the following:
  - A $13 million decrease due to a regulatory provision for refund.
  - An $11 million decrease in weather-normalized retail margins primarily in the residential and industrial classes.

  These decreases were partially offset by:
  - A $15 million increase in fuel revenues primarily due to an increase in generation at Rockport Plant.
  - A $5 million increase in rider revenues.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $23 million primarily due to an increase in generation at Rockport Plant and a purchased power disallowance in the April 2024 MPSC order on I&M's 2021 PSCR reconciliation.
- **Purchased Electricity from AEP Affiliates** increased $16 million primarily due to an increase in purchased electricity from Rockport Plant.
- **Other Operation and Maintenance** expenses increased $2 million primarily due to the following:
  - An $11 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.

  This increase was partially offset by:
  - A $4 million decrease in nuclear expenses at Cook Plant primarily due to lower refueling outage expenses.
  - A $3 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2024.
  - A $3 million decrease in vegetation management expenses.

- **Depreciation and Amortization** expenses decreased $17 million primarily due to the deferral of Excess ADIT as a result of the PLR received regarding the treatment of stand alone NOLCs and the timing of refunds to customers under rate rider mechanisms.
- **Interest Expense** decreased $7 million primarily due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.
- **Income Tax Expense** decreased $59 million primarily due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
REVENUES		
Electric Generation, Transmission and Distribution	$ 647.8	$ 642.8
Sales to AEP Affiliates	1.8	1.2
Other Revenues – Affiliated	15.0	15.9
Other Revenues – Nonaffiliated	2.8	3.1
TOTAL REVENUES	667.4	663.0
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	122.6	99.2
Purchased Electricity from AEP Affiliates	61.5	45.1
Other Operation	178.2	169.7
Maintenance	52.4	58.6
Depreciation and Amortization	108.3	125.2
Taxes Other Than Income Taxes	23.3	19.5
TOTAL EXPENSES	546.3	517.3
OPERATING INCOME	121.1	145.7
Other Income (Expense):		
Other Income	3.2	0.6
Non-Service Cost Components of Net Periodic Benefit Cost	6.7	8.0
Interest Expense	(26.2)	(33.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	104.8	121.1
Income Tax Expense (Benefit)	(40.2)	18.3
NET INCOME	$ 145.0	$ 102.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	**2023**
Net Income	$ 145.0	$ 102.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $(0.2) for 2024 and 2023, Respectively	0.1	(0.7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $(0.5) for 2024 and 2023, Respectively	—	(1.9)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	0.1	(2.6)
TOTAL COMPREHENSIVE INCOME	$ 145.1	$ 100.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2022	$ 56.6	$ 988.8	$ 1,963.2	$ (0.3)	$ 3,008.3
Common Stock Dividends			(31.2)		(31.2)
Net Income			102.8		102.8
Other Comprehensive Loss				(2.6)	(2.6)
TOTAL COMMON SHAREHOLDER'S EQUITY -MARCH 31, 2023	$ 56.6	$ 988.8	$ 2,034.8	$ (2.9)	$ 3,077.3
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2023	$ 56.6	$ 997.6	$ 2,086.6	$ (0.6)	$ 3,140.2
Common Stock Dividends			(37.5)		(37.5)
Net Income			145.0		145.0
Other Comprehensive Income				0.1	0.1
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2024	$ 56.6	$ 997.6	$ 2,194.1	$ (0.5)	$ 3,247.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5.5	$ 2.1
Accounts Receivable:		
Customers	51.1	66.9
Affiliated Companies	87.4	65.0
Accrued Unbilled Revenues	0.2	0.2
Miscellaneous	4.2	8.2
Total Accounts Receivable	142.9	140.3
Fuel	72.8	88.1
Materials and Supplies	202.2	208.2
Risk Management Assets	11.2	27.8
Regulatory Asset for Under-Recovered Fuel Costs	3.8	14.8
Prepayments and Other Current Assets	41.6	46.7
TOTAL CURRENT ASSETS	480.0	528.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,664.8	5,646.8
Transmission	1,917.0	1,906.4
Distribution	3,322.7	3,254.0
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	891.3	898.5
Construction Work in Progress	314.4	301.7
Total Property, Plant and Equipment	12,110.2	12,007.4
Accumulated Depreciation, Depletion and Amortization	4,459.0	4,378.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,651.2	7,629.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	498.2	406.3
Spent Nuclear Fuel and Decommissioning Trusts	4,112.6	3,860.2
Operating Lease Assets	51.2	53.8
Deferred Charges and Other Noncurrent Assets	318.3	330.7
TOTAL OTHER NONCURRENT ASSETS	4,980.3	4,651.0
TOTAL ASSETS	$ 13,111.5	$ 12,808.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2024 and December 31, 2023
(dollars in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT LIABILITIES		
Advances from Affiliates	$ 73.2	$ 63.3
Accounts Payable:		
General	182.1	225.8
Affiliated Companies	115.9	107.3
Long-term Debt Due Within One Year – Nonaffiliated (March 31, 2024 and December 31, 2023 Amounts Include $74.8 and $81.4, Respectively, Related to DCC Fuel)	76.9	83.7
Customer Deposits	52.1	72.2
Accrued Taxes	133.5	104.7
Accrued Interest	38.1	41.3
Obligations Under Operating Leases	14.9	16.8
Regulatory Liability for Over-Recovered Fuel Costs	22.3	23.2
Other Current Liabilities	74.3	91.9
TOTAL CURRENT LIABILITIES	783.3	830.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,401.6	3,415.7
Deferred Income Taxes	1,190.6	1,169.9
Regulatory Liabilities and Deferred Investment Tax Credits	2,262.3	2,052.3
Asset Retirement Obligations	2,123.0	2,104.3
Obligations Under Operating Leases	37.1	37.7
Deferred Credits and Other Noncurrent Liabilities	65.8	57.7
TOTAL NONCURRENT LIABILITIES	9,080.4	8,837.6
TOTAL LIABILITIES	9,863.7	9,667.8
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	997.6	997.6
Retained Earnings	2,194.1	2,086.6
Accumulated Other Comprehensive Income (Loss)	(0.5)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,247.8	3,140.2
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 13,111.5	$ 12,808.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
OPERATING ACTIVITIES		
Net Income	$ 145.0	$ 102.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	108.3	125.2
Deferred Income Taxes	(60.3)	(3.3)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(11.8)	18.1
Allowance for Equity Funds Used During Construction	(3.3)	(0.5)
Mark-to-Market of Risk Management Contracts	27.1	8.8
Amortization of Nuclear Fuel	24.4	25.0
Deferred Fuel Over/Under-Recovery, Net	10.1	3.8
Change in Other Noncurrent Assets	(34.0)	(4.3)
Change in Other Noncurrent Liabilities	35.3	3.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(2.1)	52.7
Fuel, Materials and Supplies	21.3	(24.1)
Accounts Payable	(13.5)	(27.8)
Accrued Taxes, Net	28.8	21.1
Other Current Assets	11.9	(1.9)
Other Current Liabilities	(37.3)	(41.8)
Net Cash Flows from Operating Activities	249.9	257.5
INVESTING ACTIVITIES		
Construction Expenditures	(142.3)	(141.7)
Change in Advances to Affiliates, Net	—	(37.0)
Purchases of Investment Securities	(588.5)	(536.3)
Sales of Investment Securities	569.5	517.6
Acquisitions of Nuclear Fuel	(33.7)	(1.7)
Other Investing Activities	2.7	3.3
Net Cash Flows Used for Investing Activities	(192.3)	(195.8)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	499.8
Change in Advances from Affiliates, Net	9.9	(249.9)
Retirement of Long-term Debt – Nonaffiliated	(25.4)	(274.3)
Principal Payments for Finance Lease Obligations	(1.6)	(1.9)
Dividends Paid on Common Stock	(37.5)	(31.2)
Other Financing Activities	0.4	0.1
Net Cash Flows Used for Financing Activities	(54.2)	(57.4)
Net Increase in Cash and Cash Equivalents	3.4	4.3
Cash and Cash Equivalents at Beginning of Period	2.1	4.2
Cash and Cash Equivalents at End of Period	$ 5.5	$ 8.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 38.7	$ 44.4
Net Cash Paid for Income Taxes	—	2.4
Noncash Acquisitions Under Finance Leases	0.5	2.2
Construction Expenditures Included in Current Liabilities as of March 31,	63.1	61.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	3,751	3,734
Commercial	4,684	4,000
Industrial	3,539	3,418
Miscellaneous	29	30
Total Retail (a)	12,003	11,182
Wholesale (b)	590	453
Total KWhs	12,593	11,635

(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, 2024	2023
	(in degree days)	
Actual – Heating (a)	1,463	1,344
Normal – Heating (b)	1,871	1,891
Actual – Cooling (c)	—	—
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.

Ohio Power Company and Subsidiaries
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Net Income
(in millions)

First Quarter of 2023	$	78.0
Changes in Revenues:		
Retail Revenues		(25.5)
Off-system Sales		(3.6)
Transmission Revenues		3.3
Other Revenues		15.0
Total Change in Revenues		(10.8)
Changes in Expenses and Other:		
Purchased Electricity for Resale		133.9
Purchased Electricity from AEP Affiliates		(46.6)
Other Operation and Maintenance		(36.4)
Depreciation and Amortization		(30.6)
Taxes Other Than Income Taxes		(15.5)
Other Income		(0.1)
Allowance for Equity Funds Used During Construction		2.7
Non-Service Cost Components of Net Periodic Benefit Cost		(1.0)
Interest Expense		(3.5)
Total Change in Expenses and Other		2.9
Income Tax Expense		0.5
First Quarter of 2024	$	70.6

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

- **Retail Revenues** decreased $26 million primarily due to the following:
  - A $122 million decrease due to lower customer participation in OPCo’s SSO, partially offset by higher prices.
  - A $9 million decrease in weather-normalized revenues in the residential and industrial classes, partially offset by the commercial class.

  These decreases were partially offset by:
  - An $89 million increase in rider revenues.
  - A $16 million increase in weather-related usage driven by a 9% increase in heating degree days.
- **Other Revenues** increased $15 million due to the following:
  - A $10 million increase due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.
  - A $6 million increase in refundable sales of renewable energy credits.

Expenses and Other changed between years as follows:

- **Purchased Electricity for Resale** expenses decreased $134 million primarily due to the following:
  - A $177 million decrease due to lower auction volumes driven by lower customer participation in OPCo’s SSO, partially offset by higher prices.

  This decrease was partially offset by:
  - A $30 million decrease in deferrals of recoverable OVEC costs.

- **Purchased Electricity from AEP Affiliates** expenses increased $47 million primarily due to increased purchases in OPCo's SSO auction.
- **Other Operation and Maintenance** expenses increased $36 million primarily due to the following:
  - A $27 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $16 million increase in distribution expenses primarily related to recoverable storm restoration costs and recoverable vegetation management expenses.
- **Depreciation and Amortization** expenses increased $31 million primarily due to a higher depreciable base and an increase in recoverable rider depreciable expenses.
- **Taxes Other Than Income Taxes** increased $16 million primarily due to higher property taxes driven by additional investments in transmission and distribution assets and higher tax rates.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
REVENUES		
Electricity, Transmission and Distribution	$ 1,015.4	$ 1,021.8
Sales to AEP Affiliates	5.7	7.6
Other Revenues	2.7	5.2
TOTAL REVENUES	1,023.8	1,034.6
EXPENSES		
Purchased Electricity for Resale	258.7	392.6
Purchased Electricity from AEP Affiliates	46.6	—
Other Operation	293.2	273.8
Maintenance	61.3	44.3
Depreciation and Amortization	105.8	75.2
Taxes Other Than Income Taxes	150.8	135.3
TOTAL EXPENSES	916.4	921.2
OPERATING INCOME	107.4	113.4
Other Income (Expense):		
Other Income	—	0.1
Allowance for Equity Funds Used During Construction	5.5	2.8
Non-Service Cost Components of Net Periodic Benefit Cost	5.5	6.5
Interest Expense	(34.6)	(31.1)
INCOME BEFORE INCOME TAX EXPENSE	83.8	91.7
Income Tax Expense	13.2	13.7
NET INCOME	$ 70.6	$ 78.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 321.2	$ 837.8	$ 1,929.1	$ 3,088.1
Capital Contribution from Parent		50.0		50.0
Net Income			78.0	78.0
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2023	$ 321.2	$ 887.8	$ 2,007.1	$ 3,216.1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 321.2	$ 1,012.8	$ 2,237.3	$ 3,571.3
Net Income			70.6	70.6
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2024	$ 321.2	$ 1,012.8	$ 2,307.9	$ 3,641.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12.5	$ 6.4
Accounts Receivable:		
Customers	70.8	39.2
Affiliated Companies	131.5	129.2
Miscellaneous	9.9	2.3
Total Accounts Receivable	212.2	170.7
Materials and Supplies	171.6	175.0
Renewable Energy Credits	13.4	8.9
Prepayments and Other Current Assets	18.9	16.8
TOTAL CURRENT ASSETS	428.6	377.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,438.6	3,395.1
Distribution	6,948.0	6,839.4
Other Property, Plant and Equipment	1,136.1	1,125.0
Construction Work in Progress	710.4	654.0
Total Property, Plant and Equipment	12,233.1	12,013.5
Accumulated Depreciation and Amortization	2,765.7	2,713.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,467.4	9,299.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	416.6	455.0
Operating Lease Assets	67.4	69.9
Deferred Charges and Other Noncurrent Assets	547.8	641.1
TOTAL OTHER NONCURRENT ASSETS	1,031.8	1,166.0
TOTAL ASSETS	$ 10,927.8	$ 10,843.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2024 and December 31, 2023
(Unaudited)

	March 31, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 295.2	$ 110.5
Accounts Payable:		
General	305.2	320.7
Affiliated Companies	154.5	154.2
Risk Management Liabilities	6.0	6.8
Customer Deposits	76.1	62.0
Accrued Taxes	605.5	763.3
Obligations Under Operating Leases	13.1	13.5
Other Current Liabilities	176.3	183.3
TOTAL CURRENT LIABILITIES	1,631.9	1,614.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,367.4	3,366.8
Long-term Risk Management Liabilities	35.0	43.9
Deferred Income Taxes	1,158.9	1,152.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,004.5	1,003.6
Obligations Under Operating Leases	54.5	56.7
Deferred Credits and Other Noncurrent Liabilities	33.7	34.4
TOTAL NONCURRENT LIABILITIES	5,654.0	5,658.1
TOTAL LIABILITIES	7,285.9	7,272.4
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	1,012.8	1,012.8
Retained Earnings	2,307.9	2,237.3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,641.9	3,571.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,927.8	$ 10,843.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	**2023**
OPERATING ACTIVITIES		
Net Income	$ 70.6	$ 78.0
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	105.8	75.2
Deferred Income Taxes	(0.6)	2.1
Allowance for Equity Funds Used During Construction	(5.5)	(2.8)
Mark-to-Market of Risk Management Contracts	(9.7)	7.2
Property Taxes	95.0	92.0
Change in Other Noncurrent Assets	10.1	(43.2)
Change in Other Noncurrent Liabilities	11.4	(21.7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(40.2)	(20.3)
Materials and Supplies	(1.1)	(4.8)
Accounts Payable	(32.4)	(5.5)
Customer Deposits	14.2	(22.7)
Accrued Taxes, Net	(157.5)	(157.9)
Other Current Assets	(3.4)	(2.2)
Other Current Liabilities	1.5	(7.7)
Net Cash Flows from (Used for) Operating Activities	58.2	(34.3)
INVESTING ACTIVITIES		
Construction Expenditures	(241.1)	(262.0)
Other Investing Activities	5.2	4.9
Net Cash Flows Used for Investing Activities	(235.9)	(257.1)
FINANCING ACTIVITIES		
Capital Contribution from Parent	—	50.0
Change in Advances from Affiliates, Net	184.7	241.7
Principal Payments for Finance Lease Obligations	(1.3)	(1.2)
Other Financing Activities	0.4	0.4
Net Cash Flows from Financing Activities	183.8	290.9
Net Increase (Decrease) in Cash and Cash Equivalents	6.1	(0.5)
Cash and Cash Equivalents at Beginning of Period	6.4	9.6
Cash and Cash Equivalents at End of Period	$ 12.5	$ 9.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 19.1	$ 20.9
Noncash Acquisitions Under Finance Leases	0.5	0.6
Construction Expenditures Included in Current Liabilities as of March 31,	104.8	109.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

PUBLIC SERVICE COMPANY OF OKLAHOMA

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	1,451	1,388
Commercial	1,232	1,104
Industrial	1,411	1,439
Miscellaneous	283	275
Total Retail	4,377	4,206
Wholesale	47	27
Total KWhs	4,424	4,233

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, 2024	2023
	(in degree days)	
Actual – Heating (a)	912	871
Normal – Heating (b)	1,046	1,055
Actual – Cooling (c)	22	10
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.

Public Service Company of Oklahoma
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Net Income
(in millions)

First Quarter of 2023	$	(2.3)
Changes in Revenues:		
Retail Revenues (a)		(35.5)
Transmission Revenues		(0.3)
Other Revenues		6.6
Total Change in Revenues		(29.2)
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		51.2
Other Operation and Maintenance		(3.8)
Depreciation and Amortization		(6.3)
Taxes Other Than Income Taxes		0.3
Interest Income		(0.8)
Allowance for Equity Funds Used During Construction		0.9
Non-Service Cost Components of Net Periodic Benefit Cost		(0.7)
Interest Expense		8.4
Total Change in Expenses and Other		49.2
Income Tax Benefit		54.3
First Quarter of 2024	$	72.0

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

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

- **Retail Revenues** decreased $36 million primarily due to the following:
  - A $57 million decrease in fuel revenue primarily due to lower authorized fuel rates.

  This decrease was partially offset by:
  - A $19 million increase in base rate and rider revenues.
- **Other Revenues** increased $7 million due to the following:
  - A $4 million increase in associated business development revenues.
  - A $3 million increase in affiliated rent revenues.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $51 million primarily due to the lower current year amortization of under-recovered fuel regulatory assets driven by lower authorized fuel rates.
- **Depreciation and Amortization** expenses increased $6 million primarily due to an increase in the amortization of regulatory assets related to NCWF.
- **Interest Expense** decreased $8 million primarily due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.
- **Income Tax Benefit** increased $54 million primarily due to the following:
  - A $49 million increase due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.
  - A $10 million increase in PTCs.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	**2023**
REVENUES		
Electric Generation, Transmission and Distribution	$ 378.1	$ 414.8
Sales to AEP Affiliates	3.5	0.7
Other Revenues	6.2	1.5
TOTAL REVENUES	387.8	417.0
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	148.9	200.1
Other Operation	96.6	92.1
Maintenance	28.1	28.8
Depreciation and Amortization	67.4	61.1
Taxes Other Than Income Taxes	17.0	17.3
TOTAL EXPENSES	358.0	399.4
OPERATING INCOME	29.8	17.6
Other Income (Expense):		
Interest Income	0.2	1.0
Allowance for Equity Funds Used During Construction	2.4	1.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.9	3.6
Interest Expense	(16.8)	(25.2)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT)	18.5	(1.5)
Income Tax Expense (Benefit)	(53.5)	0.8
NET INCOME (LOSS)	$ 72.0	$ (2.3)

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31,	
	2024	2023
Net Income (Loss)	$ 72.0	$ (2.3)
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $(0.4) in 2024 and 2023, Respectively	—	(1.5)
TOTAL COMPREHENSIVE INCOME (LOSS)	$ 72.0	$ (3.8)

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 157.2	$ 1,042.6	$ 1,218.0	$ 1.3	$ 2,419.1
Common Stock Dividends			(17.5)		(17.5)
Net Loss			(2.3)		(2.3)
Other Comprehensive Loss				(1.5)	(1.5)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2023	$ 157.2	$ 1,042.6	$ 1,198.2	$ (0.2)	$ 2,397.8
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 157.2	$ 1,039.3	$ 1,374.3	$ (0.2)	$ 2,570.6
Common Stock Dividends			(35.0)		(35.0)
Net Income			72.0		72.0
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2024	$ 157.2	$ 1,039.3	$ 1,411.3	$ (0.2)	$ 2,607.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.5	$ 2.5
Accounts Receivable:		
Customers	74.1	107.6
Affiliated Companies	69.1	31.0
Miscellaneous	1.0	0.8
Total Accounts Receivable	144.2	139.4
Fuel	32.5	33.7
Materials and Supplies	111.0	106.9
Risk Management Assets	7.9	19.0
Accrued Tax Benefits	43.7	31.0
Regulatory Asset for Under-Recovered Fuel Costs	155.8	118.3
Prepayments and Other Current Assets	34.8	18.7
TOTAL CURRENT ASSETS	533.4	469.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,704.8	2,695.5
Transmission	1,240.0	1,228.3
Distribution	3,513.0	3,450.8
Other Property, Plant and Equipment	514.6	505.9
Construction Work in Progress	336.9	313.7
Total Property, Plant and Equipment	8,309.3	8,194.2
Accumulated Depreciation and Amortization	2,119.7	2,081.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,189.6	6,112.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	533.1	522.7
Employee Benefits and Pension Assets	69.6	68.4
Operating Lease Assets	111.1	112.8
Deferred Charges and Other Noncurrent Assets	92.9	49.2
TOTAL OTHER NONCURRENT ASSETS	806.7	753.1
TOTAL ASSETS	$ 7,529.7	$ 7,334.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2024 and December 31, 2023
(Unaudited)

	March 31, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 264.6	$ 54.4
Accounts Payable:		
General	138.5	159.3
Affiliated Companies	59.8	56.7
Long-term Debt Due Within One Year – Nonaffiliated	125.6	0.6
Risk Management Liabilities	28.5	28.9
Customer Deposits	82.2	81.4
Accrued Taxes	67.3	30.7
Accrued Interest	26.3	30.7
Obligations Under Operating Leases	10.7	10.1
Other Current Liabilities	54.3	106.2
TOTAL CURRENT LIABILITIES	857.8	559.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,259.3	2,384.0
Deferred Income Taxes	881.6	831.2
Regulatory Liabilities and Deferred Investment Tax Credits	701.6	765.6
Asset Retirement Obligations	85.0	83.9
Obligations Under Operating Leases	104.7	106.8
Deferred Credits and Other Noncurrent Liabilities	32.1	33.8
TOTAL NONCURRENT LIABILITIES	4,064.3	4,205.3
TOTAL LIABILITIES	4,922.1	4,764.3
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	1,039.3	1,039.3
Retained Earnings	1,411.3	1,374.3
Accumulated Other Comprehensive Income (Loss)	(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,607.6	2,570.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,529.7	$ 7,334.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
OPERATING ACTIVITIES		
Net Income (Loss)	$ 72.0	$ (2.3)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	67.4	61.1
Deferred Income Taxes	(15.5)	12.2
Allowance for Equity Funds Used During Construction	(2.4)	(1.5)
Mark-to-Market of Risk Management Contracts	12.5	13.9
Property Taxes	(45.9)	(45.6)
Deferred Fuel Over/Under-Recovery, Net	(37.6)	49.4
Change in Other Noncurrent Assets	(18.4)	(9.7)
Change in Other Noncurrent Liabilities	1.7	1.4
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4.8)	27.2
Fuel, Materials and Supplies	(2.9)	12.9
Accounts Payable	(4.5)	(62.8)
Accrued Taxes, Net	23.9	24.9
Other Current Assets	(16.1)	0.4
Other Current Liabilities	(46.9)	(7.5)
Net Cash Flows from (Used for) Operating Activities	(17.5)	74.0
INVESTING ACTIVITIES		
Construction Expenditures	(156.9)	(146.8)
Acquisitions of Renewable Energy Facilities	—	(145.7)
Other Investing Activities	1.0	0.4
Net Cash Flows Used for Investing Activities	(155.9)	(292.1)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	469.9
Change in Advances from Affiliates, Net	210.2	(233.5)
Retirement of Long-term Debt – Nonaffiliated	(0.1)	(0.1)
Principal Payments for Finance Lease Obligations	(0.8)	(0.8)
Dividends Paid on Common Stock	(35.0)	(17.5)
Other Financing Activities	0.1	(0.1)
Net Cash Flows from Financing Activities	174.4	217.9
Net Increase (Decrease) in Cash and Cash Equivalents	1.0	(0.2)
Cash and Cash Equivalents at Beginning of Period	2.5	4.0
Cash and Cash Equivalents at End of Period	$ 3.5	$ 3.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 30.3	$ 22.3
Cash Received from Sale of Transferable Tax Credits	(24.9)	—
Noncash Acquisitions Under Finance Leases	0.4	0.2
Construction Expenditures Included in Current Liabilities as of March 31,	47.9	63.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

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SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended March 31, 2024	2023
	(in millions of KWhs)	
Retail:		
Residential	1,509	1,351
Commercial	1,240	1,168
Industrial	1,227	1,203
Miscellaneous	17	17
Total Retail	3,993	3,739
Wholesale	1,374	1,270
Total KWhs	5,367	5,009

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, 2024	2023
	(in degree days)	
Actual – Heating (a)	555	401
Normal – Heating (b)	697	705
Actual – Cooling (c)	88	107
Normal – Cooling (b)	44	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.

Southwestern Electric Power Company
Reconciliation of First Quarter of 2023 to First Quarter of 2024
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

First Quarter of 2023	$	40.6
Changes in Revenues:		
Retail Revenues (a)		(0.6)
Off-system Sales		2.5
Transmission Revenues		(2.9)
Other Revenues		1.3
Total Change in Revenues		0.3
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation		24.7
Other Operation and Maintenance		(13.2)
Depreciation and Amortization		1.7
Taxes Other Than Income Taxes		1.9
Interest Income		(1.4)
Allowance for Equity Funds Used During Construction		2.9
Non-Service Cost Components of Net Periodic Benefit Cost		(0.8)
Interest Expense		11.5
Total Change in Expenses and Other		27.3
Income Tax Benefit		140.1
Equity Earnings of Unconsolidated Subsidiary		0.1
Net Income Attributable to Noncontrolling Interest		(0.3)
First Quarter of 2024	$	208.1

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

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

- **Retail Revenues** decreased $1 million primarily due to the following:
  - A $39 million decrease in fuel revenue primarily due to authorized fuel rate decreases in Arkansas and Louisiana, which were primarily driven by lower natural gas and spot market energy prices.

  This decrease was partially offset by:
  - A $32 million increase in weather-normalized margins primarily in the residential and commercial classes.
  - A $5 million increase in weather-related usage primarily due to a 38% increase in heating degree days.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $25 million primarily due to a current year decrease in amortization of under-recovered fuel regulatory assets.
- **Other Operation and Maintenance** expenses increased $13 million primarily due to a disallowance recorded on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.
- **Interest Expense** decreased $12 million primarily due to the following:
  - A $28 million decrease due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.

This decrease was partially offset by:

- A $12 million increase due to a decrease in carrying charges on storm-related regulatory assets due to a prior year settlement agreement in Louisiana.

- **Income Tax Benefit** increased $140 million primarily due to the following:
  - A $109 million increase due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand alone NOLCs in retail rate making.
  - A $32 million increase due to the reversal of a regulatory liability related to the merchant portion of Turk Plant Excess ADIT as a result of the APSC's March 2024 denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
REVENUES		
Electric Generation, Transmission and Distribution	$ 500.2	$ 503.7
Sales to AEP Affiliates	12.1	11.7
Other Revenues	3.9	0.5
TOTAL REVENUES	516.2	515.9
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	184.6	209.3
Other Operation	112.9	99.2
Maintenance	37.2	37.7
Depreciation and Amortization	78.7	80.4
Taxes Other Than Income Taxes	34.2	36.1
TOTAL EXPENSES	447.6	462.7
OPERATING INCOME	68.6	53.2
Other Income (Expense):		
Interest Income	4.0	5.4
Allowance for Equity Funds Used During Construction	3.4	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.6	3.4
Interest Expense	(13.5)	(25.0)
INCOME BEFORE INCOME TAX BENEFIT AND EQUITY EARNINGS	65.1	37.5
Income Tax Benefit	(144.1)	(4.0)
Equity Earnings of Unconsolidated Subsidiary	0.4	0.3
NET INCOME	209.6	41.8
Net Income Attributable to Noncontrolling Interest	1.5	1.2
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 208.1	$ 40.6

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
Net Income	$ 209.6	$ 41.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $0 and $0.1 in 2024 and 2023, Respectively	(0.1)	0.4
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $(0.1) in 2024 and 2023, Respectively	(0.1)	(0.3)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.2)	0.1
TOTAL COMPREHENSIVE INCOME	209.4	41.9
Total Comprehensive Income Attributable to Noncontrolling Interest	1.5	1.2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 207.9	$ 40.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Three Months Ended March 31, 2024 and 2023
(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, 2022	$ 0.1	$ 1,442.2	$ 2,236.0	$ (4.2)	$ 0.7	$ 3,674.8
Capital Contribution from Parent		50.0				50.0
Common Stock Dividends – Nonaffiliated					(1.5)	(1.5)
Net Income			40.6		1.2	41.8
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – MARCH 31, 2023	$ 0.1	$ 1,492.2	$ 2,276.6	$ (4.1)	$ 0.4	$ 3,765.2
TOTAL EQUITY – DECEMBER 31, 2023	$ 0.1	$ 1,492.2	$ 2,281.3	$ (3.4)	$ 0.2	$ 3,770.4
Common Stock Dividends			(50.0)			(50.0)
Common Stock Dividends – Nonaffiliated					(1.4)	(1.4)
Net Income			208.1		1.5	209.6
Other Comprehensive Loss				(0.2)		(0.2)
TOTAL EQUITY – MARCH 31, 2024	$ 0.1	$ 1,492.2	$ 2,439.4	$ (3.6)	$ 0.3	$ 3,928.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
March 31, 2024 and December 31, 2023
(in millions)
(Unaudited)

	March 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.8	$ 2.4
Advances to Affiliates	2.3	2.2
Accounts Receivable:		
Customers	32.7	39.0
Affiliated Companies	61.2	47.2
Miscellaneous	10.3	8.3
Total Accounts Receivable	104.2	94.5
Fuel	103.4	113.8
Materials and Supplies (March 31, 2024 and December 31, 2023 Amounts Include $3.2 and $3.9, Respectively, Related to Sabine)	84.5	88.4
Accrued Tax Benefits	31.2	28.4
Regulatory Asset for Under-Recovered Fuel Costs	166.3	170.8
Prepayments and Other Current Assets	52.4	40.8
TOTAL CURRENT ASSETS	548.1	541.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,790.0	4,790.7
Transmission	2,681.1	2,660.6
Distribution	2,881.8	2,824.1
Other Property, Plant and Equipment (March 31, 2024 and December 31, 2023 Amounts Include $179.9 and $182.7, Respectively, Related to Sabine)	819.2	814.4
Construction Work in Progress	644.4	555.8
Total Property, Plant and Equipment	11,816.5	11,645.6
Accumulated Depreciation and Amortization (March 31, 2024 and December 31, 2023 Amounts Include $179.9 and $182.7, Respectively, Related to Sabine)	3,149.8	3,087.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,666.7	8,558.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,138.2	1,131.8
Deferred Charges and Other Noncurrent Assets	395.0	326.1
TOTAL OTHER NONCURRENT ASSETS	1,533.2	1,457.9
TOTAL ASSETS	$ 10,748.0	$ 10,557.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
March 31, 2024 and December 31, 2023
(Unaudited)

	March 31, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 254.5	$ 88.7
Accounts Payable:		
General	185.3	198.9
Affiliated Companies	49.3	45.9
Short-term Debt – Nonaffiliated	5.4	4.3
Customer Deposits	74.1	72.5
Accrued Taxes	128.5	58.7
Accrued Interest	37.4	39.9
Obligations Under Operating Leases	8.8	9.0
Other Current Liabilities	108.0	169.0
TOTAL CURRENT LIABILITIES	851.3	686.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,647.6	3,646.9
Deferred Income Taxes	1,254.2	1,179.3
Regulatory Liabilities and Deferred Investment Tax Credits	566.9	756.1
Asset Retirement Obligations	240.3	258.6
Employee Benefits and Pension Obligations	43.8	43.1
Obligations Under Operating Leases	120.8	122.5
Deferred Credits and Other Noncurrent Liabilities	94.7	93.8
TOTAL NONCURRENT LIABILITIES	5,968.3	6,100.3
TOTAL LIABILITIES	6,819.6	6,787.2
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	1,492.2	1,492.2
Retained Earnings	2,439.4	2,281.3
Accumulated Other Comprehensive Income (Loss)	(3.6)	(3.4)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,928.1	3,770.2
Noncontrolling Interest	0.3	0.2
TOTAL EQUITY	3,928.4	3,770.4
TOTAL LIABILITIES AND EQUITY	$ 10,748.0	$ 10,557.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended March 31, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 209.6	$ 41.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	78.7	80.4
Deferred Income Taxes	(118.5)	10.8
Allowance for Equity Funds Used During Construction	(3.4)	(0.5)
Mark-to-Market of Risk Management Contracts	1.7	9.9
Property Taxes	(74.3)	(77.5)
Deferred Fuel Over/Under-Recovery, Net	22.8	42.9
Change in Other Noncurrent Assets	(10.2)	7.2
Change in Other Noncurrent Liabilities	(0.3)	(3.3)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(9.7)	29.9
Fuel, Materials and Supplies	9.4	(4.3)
Accounts Payable	(29.6)	(47.8)
Accrued Taxes, Net	67.0	62.3
Other Current Assets	(17.7)	7.3
Other Current Liabilities	(55.7)	(48.9)
Net Cash Flows from Operating Activities	69.8	110.2
INVESTING ACTIVITIES		
Construction Expenditures	(182.6)	(201.9)
Change in Advances to Affiliates, Net	(0.1)	—
Other Investing Activities	3.0	0.4
Net Cash Flows Used for Investing Activities	(179.7)	(201.5)
FINANCING ACTIVITIES		
Capital Contribution from Parent	—	50.0
Issuance of Long-term Debt – Nonaffiliated	—	347.3
Change in Short-term Debt – Nonaffiliated	1.1	16.0
Change in Advances from Affiliates, Net	165.8	(291.9)
Retirement of Long-term Debt – Nonaffiliated	—	(94.1)
Principal Payments for Finance Lease Obligations	(4.4)	(14.8)
Dividends Paid on Common Stock	(50.0)	—
Dividends Paid on Common Stock – Nonaffiliated	(1.4)	(1.5)
Other Financing Activities	0.2	0.1
Net Cash Flows from Financing Activities	111.3	11.1
Net Increase (Decrease) in Cash and Cash Equivalents	1.4	(80.2)
Cash and Cash Equivalents at Beginning of Period	2.4	88.4
Cash and Cash Equivalents at End of Period	$ 3.8	$ 8.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 41.2	$ 45.3
Cash Received from the Sale of Transferable Tax Credits	(19.9)	—
Noncash Acquisitions Under Finance Leases	0.4	0.9
Construction Expenditures Included in Current Liabilities as of March 31,	79.4	113.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 99.

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, 2024 is not necessarily indicative of results that may be expected for the year ending December 31, 2024. The condensed financial statements are unaudited and should be read in conjunction with the audited 2023 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 26, 2024.

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,			
	2024		2023	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,003.1		$ 397.0	
Weighted-Average Number of Basic AEP Common Shares Outstanding	526.6	$ 1.91	514.2	$ 0.77
Weighted-Average Dilutive Effect of Stock-Based Awards	1.0	(0.01)	1.4	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	527.6	$ 1.90	515.6	$ 0.77

There were no antidilutive shares outstanding as of March 31, 2024 and 2023.

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, 2024		
	AEP	AEP Texas	APCo
	(in millions)		
Cash and Cash Equivalents	$ 230.7	$ 0.1	$ 7.6
Restricted Cash	51.1	42.7	8.4
Total Cash, Cash Equivalents and Restricted Cash	$ 281.8	$ 42.8	$ 16.0

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

2. NEW ACCOUNTING STANDARDS

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

Management reviews the FASB's standard-setting process and the SEC's rulemaking activity to determine the relevance, if any, to the Registrants' business. The following standards/rules will impact the Registrants' financial statements.

SEC Climate Disclosure Rule

On March 6, 2024, the SEC adopted final rules that require Registrants to disclose certain climate-related information in registration statements and annual reports. The final rules require Registrants to disclose, among other things, material climate-related risks, activities to mitigate such risks and information about Registrant's board of directors oversight and management's role in managing material climate-related risks. The final rules also require the Registrants to provide information related to any climate-related targets or goals that are material to Registrant's business, results of operations, or financial condition. A majority of the reporting requirements are applicable to the fiscal year beginning in 2025, with the addition of assurance reporting for greenhouse gas emissions starting in 2029 for large accelerated filers. Litigation challenging the new rules was filed by multiple parties in multiple jurisdictions, which have been consolidated and assigned to the U.S. Court of Appeals for the Eighth Circuit. On April 4, 2024, the SEC issued an order staying the final climate disclosure rules pending the completion of judicial review at the Court of Appeals. The Registrants are currently evaluating the impact of the final rules on their respective consolidated financial statements and related disclosures.

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

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

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

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

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

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

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

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

The amendments in the new standard are effective on a retrospective basis for all entities for fiscal years beginning after December 15, 2023 and interim periods within fiscal periods beginning after December 15, 2024 with early adoption permitted. Management plans to adopt ASU 2023-07 effective for the 2024 10-K.

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide AEP's components of changes in AOCI and details of reclassifications from AOCI. 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.

Three Months Ended March 31, 2024	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2023	$ 104.9	$ (8.1)	$ (152.3)	$ (55.5)
Change in Fair Value Recognized in AOCI, Net of Tax	5.5	12.4	—	17.9
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(29.3)	—	—	(29.3)
Interest Expense (a)	—	(1.2)	—	(1.2)
Amortization of Prior Service Cost (Credit)	—	—	(1.3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	—	0.5	0.5
Reclassifications from AOCI, before Income Tax Benefit	(29.3)	(1.2)	(0.8)	(31.3)
Income Tax Benefit	(6.1)	(0.3)	(0.2)	(6.6)
Reclassifications from AOCI, Net of Income Tax Benefit	(23.2)	(0.9)	(0.6)	(24.7)
Net Current Period Other Comprehensive Income (Loss)	(17.7)	11.5	(0.6)	(6.8)
Balance in AOCI as of March 31, 2024	$ 87.2	$ 3.4	$ (152.9)	$ (62.3)

Three Months Ended March 31, 2023	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2022	$ 223.5	$ 0.3	$ (140.1)	$ 83.7
Change in Fair Value Recognized in AOCI, Net of Tax	(195.3)	5.2	(12.9)	(203.0)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	47.0	—	—	47.0
Interest Expense (a)	—	0.7	—	0.7
Amortization of Prior Service Cost (Credit)	—	—	(5.3)	(5.3)
Amortization of Actuarial (Gains) Losses	—	—	1.2	1.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	47.0	0.7	(4.1)	43.6
Income Tax (Expense) Benefit	9.9	0.1	(0.9)	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	37.1	0.6	(3.2)	34.5
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI, Before Income Tax (Expense) Benefit	—	—	21.1	21.1
Income Tax (Expense) Benefit	—	—	4.4	4.4
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI, Net of Income Tax (Expense) Benefit	—	—	16.7	16.7
Net Current Period Other Comprehensive Income (Loss)	(158.2)	5.8	0.6	(151.8)
Balance in AOCI as of March 31, 2023	$ 65.3	$ 6.1	$ (139.5)	$ (68.1)

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

4. RATE MATTERS

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

As discussed in the 2023 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2023 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 2024 and updates the 2023 Annual Report.

Regulated Generating Units (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 in balance with reliability and other factors, which has resulted in, and in the future may result in, a proposal to retire generating facilities earlier than their currently estimated useful lives.

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

Regulated Generating Units that have been Retired

SWEPCo

In December 2021, the Dolet Hills Power Station was retired. As part of the 2020 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo's Texas jurisdictional share of the Dolet Hills Power Station through 2046, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $12 million in 2021. See the "2020 Texas Base Rate Case" section below for additional information. As part of the 2021 Arkansas Base Rate Case, the APSC authorized recovery of SWEPCo's Arkansas jurisdictional share of the Dolet Hills Power Station through 2027, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $2 million in the second quarter of 2022. Also, the APSC did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which will be addressed in a future proceeding. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Dolet Hills Power Station, through a separate rider, through 2032, but did not rule on the prudency of the early retirement of the plant, which is being addressed in a separate proceeding. In April 2024, the LPSC approved a unanimous settlement agreement filed by SWEPCo, LPSC staff and certain intervenors that resolved the prudency of the retirement of the Dolet Hills Power Station and resulted in a disallowance of $14 million in the first quarter of 2024.

In March 2023, the Pirkey Plant was retired. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana jurisdictional share of the Pirkey Plant, through a separate rider, through 2032. As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. In July 2023, Texas ALJs issued a proposal for decision that concluded the decision to retire the Pirkey Plant was prudent. In September 2023, the PUCT rejected the ALJs proposal for decision concluding the retirement of the Pirkey Plant was prudent. In the open meeting, the commissioners expressed their concerns that the analysis in support of SWEPCo's decision to retire the Pirkey Plant was not robust enough and that SWEPCo should have re-evaluated the decision following Winter Storm Uri. The treatment of the cost of recovery of the Pirkey Plant is expected to be addressed in a future rate case. As of March 31, 2024, the Texas jurisdictional share of the net book value of the Pirkey Plant was $68 million. To the extent any portion of the Texas jurisdictional share of the net book value of the Pirkey Plant is not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the Federal EPA to close Northeastern Plant, Unit 3, in 2026. The plant was originally scheduled to close in 2040. As a result of the early retirement date, PSO revised the useful life of Northeastern Plant, Unit 3, to the projected retirement date of 2026 and the incremental depreciation is being deferred as a regulatory asset. As part of the 2022 Oklahoma Base Rate Case, PSO will continue to recover Northeastern Plant, Unit 3 through 2040.

SWEPCo

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

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of March 31, 2024, 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	$ 96.7	$ 168.9	$ 20.7 (b)	2026	(c)	$ 15.1
Welsh Plant, Units 1 and 3	335.6	135.7	58.1 (d)	2028 (e)	(f)	39.2

(a) Represents the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(b) Includes Northeastern Plant, Unit 4, which was retired in 2016. Removal of Northeastern Plant, Unit 4, will be performed with the removal of Northeastern Plant, Unit 3, after retirement.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with the removal of Welsh Plant, Units 1 and 3, after retirement.
(e) Represents projected retirement date of coal assets, units are being evaluated for conversion to natural gas after 2028.
(f) Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

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

In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station. The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through rate riders. As of March 31, 2024, SWEPCo's share of the net investment in the Dolet Hills Power Station was $86 million, including materials and supplies, net of cost of removal collected in rates. Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of March 31, 2024, SWEPCo had a net under-recovered fuel balance of $72 million, inclusive of costs related to the Dolet Hills Power Station billed by DHLC, but excluding impacts of the February 2021 severe winter weather event.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $35 million of additional costs with a recovery period to be determined at a later date. In August 2022, the LPSC staff filed testimony recommending fuel disallowances of up to $55 million, including denial of recovery of the $35 million deferral, with refunds to customers over five years. In February 2024, an ALJ issued a final recommendation which included a proposed $55 million refund to customers and the denial of recovery of the $35 million deferral. SWEPCo filed a motion to present oral arguments with the LPSC to dispute the ALJ's recommendations. In April 2024, the LPSC approved a unanimous settlement agreement filed by SWEPCo, LPSC staff and certain intervenors that resolved the fuel recovery dispute and resulted in a fuel disallowance of $11 million. The remaining $24 million regulatory asset balance will be recovered over three years with interest.

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

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

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

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

In March 2023, the Pirkey Plant was retired. SWEPCo is recovering, or will seek recovery of, the remaining net book value of Pirkey Plant non-fuel costs. As of March 31, 2024, SWEPCo's share of the net investment in the Pirkey Plant was $185 million, including materials and supplies, net of cost of removal. See the "Regulated Generating Units that have been Retired" section above for additional information. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased. Additionally, as of March 31, 2024, SWEPCo had a net under-recovered fuel balance of $72 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Remaining operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses.

In July 2023, the LPSC ordered that a separate proceeding be established to review the prudence of the decision to retire the Pirkey Plant, including the costs included in fuel for years starting in 2019 and after. The LPSC established a procedural schedule stating staff and intervenor testimony is due in November 2024 and a hearing is scheduled for March 2025.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $33 million of Sabine related fuel costs through 2035.

If any of these costs are not recoverable or customer refunds are required, 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	
	March 31, 2024	**December 31, 2023**
Noncurrent Regulatory Assets	**(in millions)**	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 135.7	$ 125.6
Pirkey Plant Accelerated Depreciation	121.0	114.4
Unrecovered Winter Storm Fuel Costs (a)	90.8	97.2
Other Regulatory Assets Pending Final Regulatory Approval	14.3	49.8
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	404.9	408.9
NOLC Costs	67.7	—
Other Regulatory Assets Pending Final Regulatory Approval	89.4	78.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 923.8	$ 874.4

(a) Includes $37 million and $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of March 31, 2024 and December 31, 2023, respectively. See the "February 2021 Severe Winter Weather Impacts in SPP" section below for additional information.

Noncurrent Regulatory Assets	AEP Texas March 31, 2024	AEP Texas December 31, 2023
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 38.4	$ 37.7
Line Inspection Costs	7.4	5.7
Vegetation Management Program	5.2	5.2
Texas Retail Electric Provider Bad Debt Expense	4.1	4.0
Other Regulatory Assets Pending Final Regulatory Approval	12.1	11.7
Total Regulatory Assets Pending Final Regulatory Approval	$ 67.2	$ 64.3

Noncurrent Regulatory Assets	APCo March 31, 2024	APCo December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.7	$ 0.6
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - West Virginia	91.2	91.5
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
Other Regulatory Assets Pending Final Regulatory Approval	11.1	7.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 128.9	$ 125.5

Noncurrent Regulatory Assets	I&M March 31, 2024	I&M December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.2	$ 0.2
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - Indiana	29.7	29.7
NOLC Costs - Indiana	20.2	—
Other Regulatory Assets Pending Final Regulatory Approval	4.6	3.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 54.7	$ 33.2

Noncurrent Regulatory Assets	OPCo March 31, 2024	OPCo December 31, 2023
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 23.6	$ 23.6
Total Regulatory Assets Pending Final Regulatory Approval	$ 23.6	$ 23.6

Noncurrent Regulatory Assets	PSO March 31, 2024	PSO December 31, 2023
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 88.8	$ 88.5
NOLC Costs	12.1	—
Other Regulatory Assets Pending Final Regulatory Approval	2.9	0.2
Total Regulatory Assets Pending Final Regulatory Approval	$ 103.8	$ 88.7

Noncurrent Regulatory Assets	SWEPCo March 31, 2024	SWEPCo December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 135.7	$ 125.6
Pirkey Plant Accelerated Depreciation	121.0	114.4
Unrecovered Winter Storm Fuel Costs (a)	90.8	97.2
Dolet Hills Power Station Accelerated Depreciation (b)	12.0	12.0
Other Regulatory Assets Pending Final Regulatory Approval	1.4	26.0
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - Louisiana, Texas	51.4	56.0
NOLC Costs	35.4	—
Other Regulatory Assets Pending Final Regulatory Approval	13.9	13.7
Total Regulatory Assets Pending Final Regulatory Approval	$ 461.6	$ 444.9

(a) Includes $37 million and $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of March 31, 2024 and December 31, 2023, respectively. See the “February 2021 Severe Winter Weather Impacts in SPP” section below for additional information.
(b) Amounts include the FERC jurisdiction.

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

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

AEP Texas Interim Transmission and Distribution Rates

Through March 31, 2024, AEP Texas' cumulative revenues from interim base rate increases that are subject to a prudency review is approximately $1.1 billion. The 2024 AEP Texas base rate case described below 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.

2024 AEP Texas Base Rate Case

In February 2024, AEP Texas filed a request with the PUCT for a $164 million annual base rate increase over its adjusted test year revenues which include interim transmission and distribution rate updates. AEP Texas's request is based upon a proposed 10.6% ROE with a capital structure of 55% debt and 45% common equity. The rate case seeks a prudence determination on all capital additions included in interim rates since 2018. The procedural schedule for this case states intervenor testimony is due May 2024 and a hearing is scheduled for June 2024. If any of these costs are not recoverable or refunds of revenues collected under interim transmission and distribution rates are ordered to be returned, it could reduce future net income and cash flows and impact financial condition.

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

ENEC (Expanded Net Energy Cost) Filings

In January 2024, the WVPSC issued an order resolving the Companies' 2021-2023 ENEC cases. In the order, the WVPSC: (a) disallowed $232 million in ENEC under-recovered costs as of February 28, 2023 ($136 million related to APCo) and (b) approved the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023 ($174 million related to APCo) plus a 4% carrying charge rate over a ten-year recovery period starting September 1, 2024. In February 2024, the Companies filed briefs with the West Virginia Supreme Court to initiate an appeal of this order. The West Virginia Supreme Court will hear oral arguments in September 2024, after which it will issue a decision on the appeal. The Companies will submit their annual ENEC update filing with the WVPSC in the second quarter of 2024 proposing that updated ENEC rates become effective September 1, 2024.

2023 Virginia Base Rate Case

In March 2024, APCo filed a request with the Virginia SCC for a $95 million annual increase in base rates based upon a proposed 10.8% ROE and a proposed capital structure of 51% debt and 49% common equity. The requested increase in base rates is primarily due to incremental rate base, proposed capital structure changes including an increase in ROE and proposed increases in distribution and generation operation and maintenance expenses. Staff testimony is due in August 2024 and a hearing is scheduled for September 2024. An order is expected in the second half of 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

<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, 2024, AEP's share of ETT's cumulative revenues that are subject to a prudency review is approximately $1.7 billion. A base rate review could produce a refund to customers if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. ETT is required to file for a comprehensive rate review no later than February 1, 2025, during which the $1.7 billion of cumulative revenues above will be subject to review.

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

Michigan Power Supply Cost Recovery (PSCR)

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

In January 2024, I&M received staff testimony in I&M's 2022 PSCR Reconciliation for the 12-month period ending December 31, 2022 recommending disallowances of purchased power costs of $2 million associated with the OVEC ICPA that were alleged to be above market in applying the MPSC's Code of Conduct rules. Similar to the 2021 PSCR Reconciliation, Michigan staff also recommended several options to address I&M's shortfall in achieving Michigan's annual one percent energy waste reduction savings level, resulting in potential future disallowed costs of up to approximately $6 million. In April 2024, the MPSC issued an order on I&M's 2021 PSCR Reconciliation that: (a) disallowed $1 million of purchased power costs associated with the OVEC ICPA that the MPSC concluded were above market, (b) disallowed $10 million of purchased power costs under the Rockport Plant UPA with AEGCo that the MPSC concluded were "energy only" and above market and (c) disallowed $497 thousand of PSCR costs due to I&M's shortfall in achieving Michigan's one percent energy waste reduction savings level in 2020. As of March 31, 2024, I&M's financial statements reflect the impacts of this disallowance. I&M expects to appeal the MPSC's order.

In March 2024, I&M submitted its 2023 PSCR Reconciliation to the MPSC. An MPSC order on I&M's 2022 PSCR Reconciliation is expected in the second half of 2024. The MPSC has yet to issue a procedural schedule for I&M's 2023 PSCR Reconciliation. If any PSCR costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2023 Indiana Base Rate Case

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

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

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

2023 Michigan Base Rate Case

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

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

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

KPCo Rate Matters (Applies to AEP)

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. In February 2024, KPCo filed a motion to strike and exclude intervenor testimony. In March 2024, the KPSC denied KPCo's February 2024 motion. A hearing is expected in 2024. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce net income and cash flows and impact financial condition.

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $94 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. In conjunction with its June 2023 filing, KPCo further requested to finance through the issuance of securitization bonds, approximately $471 million of regulatory assets. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. As of March 31, 2024, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $543 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

In November 2023, KPCo filed an uncontested settlement agreement with the KPSC, that included an annual base rate increase of $75 million, based upon a 9.75% ROE. Settlement parties agreed that the KPSC should approve KPCo's securitization request, and that the approximately $471 million regulatory assets requested for securitization are comprised of prudently incurred costs.

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

In January 2024, consistent with the November 2023 uncontested settlement agreement, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets balances as of the time securitization bonds are issued and concluding that costs requested for recovery through securitization were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement and issuance that were not reflected in KPCo's proposal. As a result, in January 2024, KPCo filed a request for rehearing with the KPSC to clarify certain aspects of these additional requirements. In February 2024, the KPSC denied KPCo's rehearing requests. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the second half of 2024, subject to market conditions. As of March 31, 2024, regulatory asset balances expected to be recovered through securitization total $476 million and include: (a) $288 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $46 million of deferred purchased power expenses, (d) $62 million of under-recovered purchased power rider costs and (e) $1 million of deferred issuance-related expenses including KPSC advisor expenses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Fuel Adjustment Clause (FAC) Review

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

Rockport Offset Recovery

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

OPCo Rate Matters (Applies to AEP and OPCo)

OVEC Cost Recovery Audits

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

In May 2023, as part of the OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPCo during the 2020 audit period were imprudent and should be disallowed. A hearing was held in November 2023. In the first quarter of 2024, post-hearing briefs were filed by the parties and the case currently awaits a decision on the merits.

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

Ohio ESP Filings

In January 2023, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments, proposed new riders and the continuation and modification of certain existing riders, including the DIR, effective June 2024 through May 2030. The proposal includes a return on common equity of 10.65% on capital costs for certain riders. In June 2023, intervenors filed testimony opposing OPCo's plan for various new riders and modifications to existing riders, including the DIR. In September 2023, OPCo and certain intervenors filed a settlement agreement with the PUCO addressing the ESP application. The settlement included a four year term from June 2024 through May 2028, an ROE of 9.7% and continuation of a number of riders including the DIR subject to revenue caps. In April 2024, the PUCO issued an order approving the settlement agreement.

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

2024 Oklahoma Base Rate Case

In January 2024, PSO filed a request with the OCC for a $218 million annual base rate increase based upon a 10.8% ROE with a capital structure of 48.9% debt and 51.1% common equity. PSO requested an expanded transmission cost recovery rider and a mechanism to recover generation costs necessary to comply with SPP's 2023 increased capacity planning reserve margin requirements. PSO's request includes the 155 MW Rock Falls Wind Facility and reflects recovery of Northeastern Plant, Unit 3 through 2040. The procedural schedule for this case states intervenor testimony is due in May 2024 and a hearing is scheduled for July 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

<u>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 August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap and remanded the case to the PUCT for future proceedings. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCT. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was remanded to the PUCT for future proceedings. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

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

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. In January 2024, the PUCT established a procedural schedule for the remand proceeding. On March 1, 2024, SWEPCo filed supplemental direct testimony with the PUCT in response to the December 2023 preliminary order. On March 8, 2024, intervenors and the PUCT staff filed a motion with the PUCT to strike portions of SWEPCo's October 2023 direct testimony and March 2024 supplemental direct testimony. On March 19, 2024, The ALJ granted portions of the motion which included removal of testimony supporting SWEPCo's position that refunds are not appropriate. On March 28, 2024, SWEPCo filed an appeal of the ALJ decision with the PUCT. A decision by the PUCT on the appeal is expected in the second quarter of 2024. In April 2024, intervenors and PUCT staff submitted testimony recommending customer refunds through December 2023 ranging from $149 million to $197 million, including carrying charges, with refund periods ranging from 18 months to 48 months. A hearing is scheduled for May 2024. Although SWEPCo does not currently believe any refunds are probable of occurring, SWEPCo estimates it could be required to make customer refunds, including interest, ranging from $0 to $200 million related to revenues collected from February 2013 through March 2024.

2016 Texas Base Rate Case

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

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

2020 Texas Base Rate Case

In October 2020, SWEPCo filed a request with the PUCT for a $105 million annual increase in Texas base rates based upon a proposed 10.35% ROE. The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $90 million primarily due to increased investments. SWEPCo subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to $100 million, which would result in an $85 million net annual base rate increase after moving the proposed riders to rate base.

In January 2022, the PUCT issued a final order approving an annual revenue increase of $39 million based upon a 9.25% ROE. The order also includes: (a) rates implemented retroactively back to March 18, 2021, (b) $5 million of the proposed increase related to vegetation management, (c) $2 million annually to establish a storm catastrophe reserve and (d) the creation of a rider to recover the Dolet Hills Power Station as if it were in rate base until its retirement at the end of 2021 and starting in 2022 the remaining net book value to be recovered as a regulatory asset through 2046. As a result of the final order, SWEPCo recorded a disallowance of $12 million in 2021 associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging several errors in the order, which include challenges of the approved ROE, the denial of a reasonable return or carrying costs on the Dolet Hills Power Station and the calculation of the Texas jurisdictional share of the storm catastrophe reserve. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order.

2021 Louisiana Storm Cost Filing

In 2020, Hurricanes Laura and Delta caused power outages and extensive damage to the SWEPCo service territories, primarily impacting the Louisiana jurisdiction. Following both hurricanes, the LPSC issued orders allowing Louisiana utilities, including SWEPCo, to establish regulatory assets to track and defer expenses associated with these storms. In February 2021, severe winter weather impacted the Louisiana jurisdiction and in March 2021, the LPSC approved the deferral of incremental storm restoration expenses related to the winter storm. In March 2023, SWEPCo and the LPSC staff filed a joint stipulation and settlement agreement with the LPSC which confirmed the prudency of $150 million of deferred incremental storm restoration expenses. The agreement also authorized an interim carrying charge at a rate of 3.125% through March 2024. In April 2023, the LPSC issued an order approving the stipulation and settlement agreement. In July 2023, SWEPCo submitted additional information in phase two of this proceeding to obtain a financing order and prudency review of capital investment. In April 2024, SWEPCo and the LPSC staff filed a joint uncontested stipulation and settlement agreement with the LPSC requesting securitization of storm costs, including a storm reserve. A hearing is scheduled for May 2024. If SWEPCo is unable to recover he regulatory assets associated with these storms, it could reduce future net income and cash flows and impact financial condition.

February 2021 Severe Winter Weather Impacts in SPP

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

Jurisdiction	March 31, 2024	December 31, 2023	Approved Recovery Period	Approved Carrying Charge
	(in millions)			
Arkansas	$ 48.6	$ 54.2	6 years	(a)
Louisiana	90.8	97.2	(b)	(b)
Texas	94.5	101.9	5 years	1.65%
Total	$ 233.9	$ 253.3		

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

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

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

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

North Central Wind Energy Facilities

The NCWF are subject to various regulatory performance requirements, including a Net Capacity Factor (NCF) guarantee. The NCF guarantee will be measured in MWhs across all facilities on a combined basis for each five year period for the first thirty full years of operation. The first NCF guarantee five year period began in April 2022. Certain wind turbines have experienced performance issues that have prompted PSO and SWEPCo to work with a manufacturer to find a resolution. If regulatory performance requirements, such as the NCF guarantee, are not met, PSO and SWEPCo may recognize a regulatory liability to refund retail customers. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

<u>FERC Rate Matters</u>

Independence Energy Connection Project (Applies to AEP)

In 2016, PJM approved the Independence Energy Connection Project (IEC) and included it in its Regional Transmission Expansion Plan to alleviate congestion. Transource Energy has an ownership interest in the IEC, which is located in Maryland and Pennsylvania. In June 2020, the Maryland Public Service Commission approved a Certificate of Public Convenience and Necessity to construct the portion of the IEC in Maryland. In May 2021, the Pennsylvania Public Utility Commission (PAPUC) denied the IEC certificate for siting and construction of the portion in Pennsylvania. Transource Energy appealed the PAPUC ruling in Pennsylvania state court and challenged the ruling before the United States District Court for the Middle District of Pennsylvania. In May 2022, the Pennsylvania state court issued an order affirming the PAPUC decision as to state law claims. In December 2023, the United States District Court for the Middle District of Pennsylvania granted summary judgment in favor of Transource Energy, finding that the PAPUC decision violated federal law and the United States Constitution. In January 2024, the PAPUC filed an appeal with the United States Court of Appeals for the Third Circuit. Additional regulatory proceedings before the PAPUC are expected to resume in 2024.

In September 2021, PJM notified Transource Energy that the IEC was suspended to allow for the regulatory and related appeals process to proceed in an orderly manner without breaching milestone dates in the project agreement. At that time, PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. PJM continues to evaluate reliability and market efficiency in the area. As of March 31, 2024, AEP's share of IEC capital expenditures was approximately $94 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.

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

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

In December 2022, the FERC issued an order approving the proposed AEGCo Rockport depreciation rates effective January 1, 2023, subject to further review and a potential refund. In August 2023, AEGCo reached a settlement agreement with the FERC trial staff that resolved all issues set for hearing. In September 2023, the settlement agreement was certified to the FERC as uncontested. In March 2024, the FERC issued an order approving the uncontested settlement agreement. The results of the order did not have a material impact on financial condition, results of operations or cash flows.

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

The Registrants transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements, and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2024, 2023, 2022 and 2021 by $52 million, $60 million, $69 million and $78 million, respectively.

In January 2024, the FERC issued two orders granting formal challenges by certain unaffiliated customers related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEP made filings with the FERC which request that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. The Registrants have not yet been directed to make cash refunds related to the 2024, 2023 or 2022 rate years.

As a result of the January 2024 FERC orders, the Registrants' balance sheets reflect a liability for the probable refund of all NOLC revenues included in transmission formula rates for years 2024, 2023, 2022 and 2021, with interest. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets, with the exception of amounts expected to be refunded within one year which are reflected in Other Current Liabilities. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms.

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

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

5. 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 2023 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, AEP Texas, APCo and I&M)

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

In March 2024, AEP increased its $4 billion revolving credit facility to $5 billion and extended the due date from March 2027 to March 2029. Also, in March 2024, AEP extended the due date of its $1 billion revolving credit facility from March 2025 to March 2027. AEP may issue up to $1.2 billion as letters of credit, under these revolving credit facilities, on behalf of subsidiaries. As of March 31, 2024, no letters of credit were issued under either revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of March 31, 2024 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 247.4	April 2024 to March 2025
AEP Texas	1.8	July 2024
APCo	6.3	September 2024
I&M	2.9	September 2024

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2024, there were no material liabilities recorded for any indemnifications.

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

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, 2024, 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	$	44.6
AEP Texas		10.7
APCo		5.8
I&M		4.1
OPCo		7.1
PSO		4.5
SWEPCo		5.1

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

Proposed Revisions to CCR Rule

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities (“legacy CCR surface impoundments”) as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land (“CCR management units”). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. AEP is evaluating the applicability of the rule to current and former plant sites and is working to develop estimates of compliance costs, which are expected to be material, including costs to upgrade or close and replace legacy CCR surface impoundments and to conduct any required remedial actions including removal of coal ash.

Closure and post-closure estimated costs for facilities subject to the original CCR Rule have been included in ARO in accordance with the requirements in the Federal EPA’s original CCR rule. Material ARO revisions will be necessary to address the expanded scope of facilities subject to the revised rule. Additional material ARO revisions may 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.

AEP would need to seek cost recovery through regulated rates, including proposing new regulatory mechanisms for cost recovery where existing mechanisms are not applicable, for which regulatory approval cannot be assured. The rule could have a material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover any additional costs of compliance. Management is also evaluating potential legal challenges to the revised rule.

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. Management is currently evaluating applying for license extensions for both units. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

OPERATIONAL CONTINGENCIES

Litigation Related to Ohio House Bill 6 (HB 6)

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

In August 2020, an AEP shareholder filed a putative class action lawsuit in the U. S. District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. In December 2021, the district court issued an opinion and order dismissing the securities litigation complaint with prejudice, determining that the complaint failed to plead any actionable misrepresentations or omissions. The plaintiffs did not appeal the ruling.

In January 2021, an AEP shareholder filed a derivative action in the U.S. District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The court entered a scheduling order in the New York state court derivative action staying the case other than with respect to briefing the motion to dismiss. AEP filed substantive and forum-based motions to dismiss in April 2022. In June 2022, the Ohio state court entered an order continuing the stays of that case until the final resolution of the consolidated derivative actions pending in Ohio federal district court. In September 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiff subsequently filed a notice of appeal with the New York appellate court. In January 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York. The two derivative actions pending in federal district court in Ohio have been consolidated and the plaintiffs in the consolidated action filed an amended complaint. AEP filed a motion to dismiss the amended complaint and subsequently filed a brief in opposition to the New York plaintiffs' motion to intervene in the consolidated action in Ohio. In March 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. In April 2023, one of the plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Sixth Circuit of the Ohio federal district court order dismissing the consolidated action and denying the intervention. The defendants will continue to defend against the claims. Management does not believe the range of potential losses that is reasonably possible of occurring will have a material impact on results of operations, cash flows or financial condition.

In March 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter was directed to the Board of Directors of AEP (AEP Board) and contained factual allegations involving HB 6 that were generally consistent with those in the derivative litigation filed in state and federal court. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect. In April 2023, AEP received a litigation demand from counsel representing the purported AEP shareholder who filed the dismissed derivative action in New York state court and unsuccessfully tried to intervene in the consolidated derivative actions in Ohio federal court. The litigation demand letter is directed to the AEP Board and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by certain current and former directors and officers, and that AEP commence a civil action for breaches of fiduciary duty and related claims against any individuals who allegedly harmed AEP. The AEP Board considered the 2023 litigation demand letter and formed a committee of the Board (the "Demand Review Committee") to investigate, review, monitor and analyze the allegations in the letter and make a recommendation to the AEP Board regarding a reasonable and appropriate response to the same. The AEP Board will act in response to the letter as appropriate. Management does not believe the range of potential losses that is reasonably possible of occurring will have a material impact on results of operations, cash flows or financial condition.

In May 2021, AEP received a subpoena from the SEC's Division of Enforcement seeking various documents, including documents relating to the passage of HB 6 and documents relating to AEP's policies and financial processes and controls. In August 2022, AEP received a second subpoena from the SEC seeking various additional documents relating to its ongoing investigation. AEP is cooperating fully with the SEC's investigation, which has included taking testimony from certain individuals and inquiries regarding Empowering Ohio's Economy, Inc., which is a 501(c)(4) social welfare organization, and related disclosures. The SEC staff has advanced its discussions with certain parties involved in the investigation, including AEP, concerning the staff's intentions regarding potential claims under the securities laws. AEP and the SEC are engaged in discussions about a possible resolution of the SEC's investigation and potential claims under the securities laws. Any resolution or filed claims, the outcome of which cannot be predicted, may subject AEP to civil penalties and other remedial measures. Discussions are continuing and management does not believe the range of potential losses that is reasonably possible of occurring as a result of this investigation, or possible resolution thereof, will have a material impact on results of operations, cash flows or financial condition.

Claims for Indemnification Made by Owners of the Gavin Power Station

In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow a CCR surface impoundment at the Gavin Power Station to continue to receive CCR and non-CCR waste streams after April 11, 2021 until May 4, 2023 (the Gavin Denial). As part of the Gavin Denial, the Federal EPA made several assertions related to the CCR Rule (see "Environmental Issues - CCR Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information), including an assertion that the closure of the 300 acre unlined fly ash reservoir (FAR) is noncompliant with the CCR Rule in multiple respects. The Gavin Power Station was formerly owned and operated by AEP and was sold to Gavin Power LLC and Lightstone Generation LLC in 2017. Pursuant to the PSA, AEP maintained responsibility to complete closure of the FAR in accordance with the closure plan approved by the Ohio EPA which was completed in July 2021. The PSA contains indemnification provisions, pursuant to which the owners of the Gavin Power Station have notified AEP they believe they are entitled to indemnification for any damages that may result from these claims, including any future enforcement or litigation resulting from any determinations of noncompliance by the Federal EPA with various aspects of the CCR Rule consistent with the Gavin Denial. The owners of the Gavin Power Station have also sought indemnification for landowner claims for property damage allegedly caused by modifications to the FAR. Management does not believe that the owners of the Gavin Power Station have any valid claim for indemnity or otherwise against AEP under the PSA. In addition, Gavin Power LLC, several AEP subsidiaries, and other parties have filed Petitions for Review of the Gavin Denial with the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to determine a range of potential losses that is reasonably possible of occurring. In January 2024, Gavin Power LLC also filed a complaint with the United States District Court for the Southern District of Ohio, alleging various violations of the Administrative Procedure Act and asserting that the Federal EPA, through its prior inaction, has waived and is estopped from raising certain objections raised in the Gavin Denial. Management cannot predict the outcome of that litigation.

Litigation Regarding Justice Thermal Coal Contract

In December 2023, APCo filed a suit in the Franklin County Ohio Court of Common Pleas seeking a declaratory judgment confirming APCo's right to terminate a long-term coal contract with Justice Thermal LLC ("Justice Thermal") based on Justice Thermal's failure to perform under the contract. APCo terminated that contract in January 2024, and in April 2024 APCo filed an amended complaint seeking a declaration that the termination was proper and also seeking damages for Justice Thermal's breach of contract. Justice Thermal filed an answer and counterclaim in April 2024, contesting the validity of the contract termination and asserting counterclaims. Justice Thermal's counterclaims allege that APCo breached the contract, assert a claim for fraud relating to APCo's alleged fabrication of coal sample analyses, and seek damages. APCo will continue to pursue its claims and defend against the counterclaims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

6. ACQUISITIONS AND DISPOSITIONS

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

ACQUISITIONS

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

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

DISPOSITIONS

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

In February 2022, AEP management announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio (the portfolio) within the Generation & Marketing segment. In late January 2023, AEP received final bids from interested parties. In February 2023, AEP's Board of Directors approved management's plan to sell the portfolio and AEP signed an agreement with a nonaffiliated party. AEP recorded a pretax loss of $112 million ($88 million after-tax) in the first quarter of 2023 as a result of reaching Held for Sale status and determining the carrying value of the portfolio exceeded the estimated fair value.

In August 2023, AEP completed the sale of the entire portfolio to the nonaffiliated party and received cash proceeds of approximately $1.2 billion, net of taxes and transaction costs.

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

In December 2023, AEP and the joint owner signed an agreement to sell NMRD to a nonaffiliated third party and the sale was completed in February 2024. AEP received cash proceeds of approximately $107 million, net of taxes and transaction costs. The transaction did not have a material impact on net income or financial condition.

7. BENEFIT PLANS

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

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

Components of Net Periodic Benefit Cost (Credit)

Pension Plans

Three Months Ended March 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 25.6	$ 2.2	$ 2.4	$ 3.3	$ 2.4	$ 1.5	$ 1.9
Interest Cost	51.9	4.3	6.2	6.0	4.7	2.5	3.1
Expected Return on Plan Assets	(80.2)	(6.4)	(10.7)	(10.8)	(8.2)	(4.3)	(4.4)
Amortization of Net Actuarial Loss	1.1	0.1	0.1	0.1	0.1	—	0.1
Net Periodic Benefit Cost (Credit)	$ (1.6)	$ 0.2	$ (2.0)	$ (1.4)	$ (1.0)	$ (0.3)	$ 0.7

Three Months Ended March 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 23.6	$ 2.0	$ 2.3	$ 3.0	$ 2.1	$ 1.4	$ 1.9
Interest Cost	54.8	4.6	6.6	6.2	4.9	2.7	3.5
Expected Return on Plan Assets	(84.8)	(7.0)	(11.2)	(11.0)	(8.5)	(4.6)	(4.8)
Amortization of Net Actuarial Loss	0.3	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	$ (6.1)	$ (0.4)	$ (2.3)	$ (1.8)	$ (1.5)	$ (0.5)	$ 0.6

OPEB

Three Months Ended March 31, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Interest Cost	10.5	0.8	1.7	1.2	1.1	0.5	0.7
Expected Return on Plan Assets	(27.8)	(2.3)	(4.0)	(3.4)	(3.0)	(1.4)	(1.9)
Amortization of Prior Service Credit	(3.2)	(0.3)	(0.5)	(0.4)	(0.3)	(0.2)	(0.3)
Amortization of Net Actuarial Loss	0.8	0.1	0.1	0.1	0.1	—	0.1
Net Periodic Benefit Credit	$ (18.6)	$ (1.6)	$ (2.6)	$ (2.4)	$ (2.0)	$ (1.0)	$ (1.3)

Three Months Ended March 31, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.1	$ 0.1	$ 0.1	$ 0.2	$ 0.1	$ 0.1	$ 0.1
Interest Cost	11.6	0.9	1.8	1.3	1.2	0.6	0.7
Expected Return on Plan Assets	(27.4)	(2.3)	(4.0)	(3.4)	(2.9)	(1.5)	(1.8)
Amortization of Prior Service Credit	(15.8)	(1.3)	(2.3)	(2.2)	(1.6)	(1.0)	(1.2)
Amortization of Net Actuarial Loss	3.7	0.3	0.6	0.5	0.4	0.2	0.2
Net Periodic Benefit Credit	$ (26.8)	$ (2.3)	$ (3.8)	$ (3.6)	$ (2.8)	$ (1.6)	$ (2.0)

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

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

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

The tables below represent AEP's reportable segment income statement information for the three months ended March 31, 2024 and 2023 and reportable segment balance sheet information as of March 31, 2024 and December 31, 2023.

	Three Months Ended March 31, 2024						
	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	$ 2,901.2	$ 1,483.2	$ 110.5	$ 515.9	$ 14.9	$ —	$ 5,025.7
Other Operating Segments	46.7	7.0	386.8	47.6	37.9	(526.0) (b)	—
Total Revenues	$ 2,947.9	$ 1,490.2	$ 497.3	$ 563.5	$ 52.8	$ (526.0)	$ 5,025.7
Net Income (Loss)	$ 562.3	$ 150.3	$ 209.8	$ 137.6	$ (54.3)	$ —	$ 1,005.7

	Three Months Ended March 31, 2023						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 2,816.3	$ 1,455.3	$ 90.1	$ 326.9	$ 2.3	$ —	$ 4,690.9
Other Operating Segments	41.5	8.9	365.4	0.1	27.8	(443.7) (b)	—
Total Revenues	$ 2,857.8	$ 1,464.2	$ 455.5	$ 327.0	$ 30.1	$ (443.7)	$ 4,690.9
Net Income (Loss)	$ 262.2	$ 125.7	$ 182.4	$ (156.4)	$ (13.5)	$ —	$ 400.4

	March 31, 2024						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets	$ 52,379.2	$ 25,283.4	$ 17,067.4	$ 2,257.5	$ 5,164.3 (c)	$ (4,407.2) (d)	$ 97,744.6

	December 31, 2023						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets	$ 51,802.1	$ 24,838.4	$ 16,575.6	$ 2,598.5	$ 5,194.0 (c)	$ (4,324.6) (d)	$ 96,684.0

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and other nonallocated costs.
(b) Represents inter-segment revenues.
(c) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the three months ended March 31, 2024 and 2023 and reportable segment balance sheet information as of March 31, 2024 and December 31, 2023.

	Three Months Ended March 31, 2024			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 97.0	$ —	$ —	$ 97.0
Sales to AEP Affiliates	383.4	—	—	383.4
Other Revenues	2.4	—	—	2.4
Total Revenues	$ 482.8	$ —	$ —	$ 482.8
Net Income (Loss)	$ 181.7	$ (0.5) (a)	$ —	$ 181.2

	Three Months Ended March 31, 2023			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 89.0	$ —	$ —	$ 89.0
Sales to AEP Affiliates	352.6	—	—	352.6
Total Revenues	$ 441.6	$ —	$ —	$ 441.6
Net Income	$ 161.6	$ 1.1 (a)	$ —	$ 162.7

	March 31, 2024			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Total Assets	$ 15,609.4	$ 5,949.9 (b)	$ (6,000.3) (c)	$ 15,559.0

	December 31, 2023			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Total Assets	$ 15,120.6	$ 5,486.6 (b)	$ (5,534.7) (c)	$ 15,072.5

(a) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos.
(b) Primarily relates to Notes Receivable from the State Transcos.
(c) Primarily relates to the elimination of Notes Receivable from the State Transcos.

9. DERIVATIVES AND HEDGING

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments

Primary Risk Exposure	March 31, 2024							December 31, 2023						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)													
Commodity:														
Power (MWhs)	233.5	—	7.0	3.4	2.2	2.2	1.6	246.8	—	16.8	5.9	2.2	4.1	2.9
Natural Gas (MMBtus)	176.8	—	43.0	—	—	49.0	19.7	151.6	—	37.3	—	—	34.9	17.9
Heating Oil and Gasoline (Gallons)	7.7	2.0	1.1	1.2	1.3	0.8	1.0	6.5	1.8	1.0	0.6	1.2	0.7	0.9
Interest Rate (USD)	$ 69.6	$ —	$ —	$ —	$ —	$ —	$ —	$ 80.1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt (USD)	$1,500.0	$150.0	$ —	$ —	$ —	$ —	$ —	$1,300.0	$150.0	$ —	$ —	$ —	$ —	$ —

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 $86 million and $46 million as of March 31, 2024 and December 31, 2023, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for the Registrant Subsidiaries as of March 31, 2024 and December 31, 2023. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was immaterial for the Registrants as of March 31, 2024 and December 31, 2023.

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

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets. The derivative instruments are disclosed as gross. They are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging." Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	March 31, 2024						
	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 436.2	$ 0.2	$ 9.9	$ 15.5	$ 0.1	$ 8.5	$ 5.5
Hedging Contracts - Commodity	35.4	—	—	—	—	—	—
Hedging Contracts - Interest Rate	8.3	2.3	—	—	—	—	—
Total Current Risk Management Assets	479.9	2.5	9.9	15.5	0.1	8.5	5.5
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	525.0	—	1.2	—	—	—	—
Hedging Contracts - Commodity	81.0	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Long-term Risk Management Assets	606.0	—	1.2	—	—	—	—
Total Assets	$ 1,085.9	$ 2.5	$ 11.1	$ 15.5	$ 0.1	$ 8.5	$ 5.5
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 456.9	$ —	$ 21.0	$ 9.0	$ 6.0	$ 29.1	$ 9.5
Hedging Contracts - Commodity	5.1	—	—	—	—	—	—
Hedging Contracts - Interest Rate	46.1	0.1	—	—	—	—	—
Total Current Risk Management Liabilities	508.1	0.1	21.0	9.0	6.0	29.1	9.5
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	430.0	—	3.3	—	35.0	2.8	1.8
Hedging Contracts - Commodity	0.6	—	—	—	—	—	—
Hedging Contracts - Interest Rate	70.4	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	501.0	—	3.3	—	35.0	2.8	1.8
Total Liabilities	$ 1,009.1	$ 0.1	$ 24.3	$ 9.0	$ 41.0	$ 31.9	$ 11.3
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 76.8	$ 2.4	$ (13.2)	$ 6.5	$ (40.9)	$ (23.4)	$ (5.8)

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

Offsetting Assets and Liabilities

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

	March 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Assets:							
Current Risk Management Assets							
Gross Amounts Recognized	$ 479.9	$ 2.5	$ 9.9	$ 15.5	$ 0.1	$ 8.5	$ 5.5
Gross Amounts Offset	(327.2)	—	(1.2)	(4.3)	—	(0.6)	(0.2)
Net Amounts Presented	152.7	2.5	8.7	11.2	0.1	7.9	5.3
Long-term Risk Management Assets							
Gross Amounts Recognized	606.0	—	1.2	—	—	—	—
Gross Amounts Offset	(291.6)	—	(1.2)	—	—	—	—
Net Amounts Presented	314.4	—	—	—	—	—	—
Total Assets	$ 467.1	$ 2.5	$ 8.7	$ 11.2	$ 0.1	$ 7.9	$ 5.3
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 508.1	$ 0.1	$ 21.0	$ 9.0	$ 6.0	$ 29.1	$ 9.5
Gross Amounts Offset	(323.7)	—	(2.6)	(8.3)	—	(0.6)	(0.2)
Net Amounts Presented	184.4	0.1	18.4	0.7	6.0	28.5	9.3
Long-term Risk Management Liabilities							
Gross Amounts Recognized	501.0	—	3.3	—	35.0	2.8	1.8
Gross Amounts Offset	(221.5)	—	(1.2)	—	—	—	—
Net Amounts Presented	279.5	—	2.1	—	35.0	2.8	1.8
Total Liabilities	$ 463.9	$ 0.1	$ 20.5	$ 0.7	$ 41.0	$ 31.3	$ 11.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3.2	$ 2.4	$ (11.8)	$ 10.5	$ (40.9)	$ (23.4)	$ (5.8)

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

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Three Months Ended March 31, 2024						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (25.7)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(44.7)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	(25.8)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1.0	—	0.9	—	—	—	—
Maintenance	0.1	—	—	—	—	—	—
Regulatory Assets (a)	13.5	0.2	(0.1)	(1.6)	8.6	(1.2)	4.9
Regulatory Liabilities (a)	52.7	0.2	13.1	2.2	—	18.3	15.0
Total Gain (Loss) on Risk Management Contracts	$ (3.1)	$ 0.4	$ 14.0	$ (25.2)	$ 8.6	$ 17.1	$ 19.9

	Three Months Ended March 31, 2023						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (5.3)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(147.4)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	(5.3)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.7	—	0.6	—	—	—	—
Maintenance	0.1	—	—	—	—	—	—
Regulatory Assets (a)	(24.8)	(0.4)	(7.1)	(0.5)	(12.3)	(1.2)	(1.5)
Regulatory Liabilities (a)	(1.5)	—	(26.2)	1.2	—	18.0	11.9
Total Gain (Loss) on Risk Management Contracts	$ (178.2)	$ (0.4)	$ (32.7)	$ (4.6)	$ (12.3)	$ 16.8	$ 10.4

(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, 2024	**December 31, 2023**	**March 31, 2024**	**December 31, 2023**
	(in millions)			
Long-term Debt (a) (b)	$ (860.2)	$ (878.2)	$ 86.7	$ 68.4

(a) Amounts included within Noncurrent Liabilities line item Long-term Debt on the Balance Sheet.
(b) Amounts include $(28) million and $(30) million as of March 31, 2024 and December 31, 2023, 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,	
	2024	**2023**
	(in millions)	
Gain (Loss) on Interest Rate Contracts:		
Fair Value Hedging Instruments (a)	$ (16.4)	$ 6.9
Fair Value Portion of Long-term Debt (a)	16.4	(6.9)

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

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

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects net income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity, Fuel and Other Consumables Used for Electric Generation on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2024 and 2023, 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, 2024, AEP and AEP Texas applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the three months ended March 31, 2023, AEP, AEP Texas, I&M, PSO and SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on the Registrants' Balance Sheets

	March 31, 2024				December 31, 2023			
	AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months		AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months	
	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate
					(in millions)			
AEP	$ 87.2	$ 3.4	$ 24.0	$ 3.6	$ 104.9	$ (8.1)	$ 38.3	$ 3.2
AEP Texas	—	4.4	—	0.5	—	0.5	—	0.2
APCo	—	5.7	—	0.8	—	5.9	—	0.8
I&M	—	(5.4)	—	(0.4)	—	(5.5)	—	(0.4)
PSO	—	(0.2)	—	—	—	(0.2)	—	—
SWEPCo	—	1.2	—	0.3	—	1.3	—	0.3

As of March 31, 2024 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 84 months.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Credit-Risk-Related Contingent Features

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had no derivative contracts with collateral triggering events in a net liability position as of March 31, 2024 and December 31, 2023.

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 $116 million and $107 million and no cash collateral posted as of March 31, 2024 and December 31, 2023, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries' derivative contracts with cross-acceleration provisions outstanding as of March 31, 2024 and December 31, 2023 were not material.

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

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. AEP had derivative contracts with cross-default provisions in a net liability position of $235 million and $242 million and no cash collateral posted as of March 31, 2024 and December 31, 2023, respectively, after considering contractual netting arrangements. If a cross-default provision would have been triggered, settlement at fair value would have been required. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $16 million, $31 million and $10 million, respectively, and no cash collateral posted as of March 31, 2024. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $22 million, $29 million and $15 million, respectively, and no cash collateral posted as of December 31, 2023. The other Registrant Subsidiaries had no derivative contracts with cross-default provisions outstanding as of March 31, 2024 and December 31, 2023.

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:

Company	March 31, 2024 Book Value	March 31, 2024 Fair Value	December 31, 2023 Book Value	December 31, 2023 Fair Value
	(in millions)			
AEP	$ 39,835.9	$ 36,392.2	$ 40,143.2	$ 37,325.7
AEP Texas	5,878.7	5,289.7	5,889.8	5,400.7
AEPTCo	5,860.7	5,066.3	5,414.4	4,796.9
APCo	5,670.9	5,370.8	5,588.3	5,390.1
I&M	3,478.5	3,182.3	3,499.4	3,291.6
OPCo	3,367.4	2,912.1	3,366.8	2,992.1
PSO	2,384.9	2,130.2	2,384.6	2,154.3
SWEPCo	3,647.6	3,170.6	3,646.9	3,209.7

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, 2024			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash (a)	$ 51.1	$ —	$ —	$ 51.1
Other Cash Deposits	15.4	—	—	15.4
Fixed Income Securities – Mutual Funds (b)	164.7	—	(6.8)	157.9
Equity Securities – Mutual Funds	14.7	29.0	—	43.7
Total Other Temporary Investments and Restricted Cash	$ 245.9	$ 29.0	$ (6.8)	$ 268.1

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

(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, 2024	Three Months Ended March 31, 2023
	(in millions)	
Proceeds from Investment Sales	$ 3.0	$ —
Purchases of Investments	1.5	1.0
Gross Realized Gains on Investment Sales	0.3	—
Gross Realized Losses on Investment Sales	0.2	—

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

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

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

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

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

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

The following is a summary of nuclear trust fund investments:

	March 31, 2024				December 31, 2023			
	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments
	(in millions)							
Cash and Cash Equivalents	$ 25.2	$ —	$ —	$ —	$ 16.8	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,267.0	16.5	(4.2)	(25.7)	1,273.0	28.6	(3.9)	(33.2)
Corporate Debt	123.3	2.5	(6.0)	(5.1)	132.1	4.8	(5.2)	(8.6)
State and Local Government	1.7	—	—	—	1.7	—	—	—
Subtotal Fixed Income Securities	1,392.0	19.0	(10.2)	(30.8)	1,406.8	33.4	(9.1)	(41.8)
Equity Securities - Domestic	2,695.4	2,119.1	(1.1)	—	2,436.6	1,869.5	(0.9)	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 4,112.6	$ 2,138.1	$ (11.3)	$ (30.8)	$3,860.2	$ 1,902.9	$ (10.0)	$ (41.8)

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

	Three Months Ended March 31, 2024	2023
	(in millions)	
Proceeds from Investment Sales	$ 569.5	$ 517.6
Purchases of Investments	588.5	536.3
Gross Realized Gains on Investment Sales	5.4	48.5
Gross Realized Losses on Investment Sales	1.2	8.6

The base cost of fixed income securities was $1.4 billion and $1.4 billion as of March 31, 2024 and December 31, 2023, respectively. The base cost of equity securities was $577 million and $568 million as of March 31, 2024 and December 31, 2023, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of March 31, 2024 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 338.8
After 1 year through 5 years	598.0
After 5 years through 10 years	186.6
After 10 years	268.6
Total	$ 1,392.0

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, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 51.1	$ —	$ —	$ —	$ 51.1
Other Cash Deposits (a)	—	—	—	15.4	15.4
Fixed Income Securities – Mutual Funds	157.9	—	—	—	157.9
Equity Securities – Mutual Funds (b)	43.7	—	—	—	43.7
Total Other Temporary Investments and Restricted Cash	252.7	—	—	15.4	268.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.6	679.7	257.5	(593.9)	346.9
Cash Flow Hedges:					
Commodity Hedges (c)	—	94.5	18.7	(1.3)	111.9
Interest Rate Hedges	—	8.3	—	—	8.3
Total Risk Management Assets	3.6	782.5	276.2	(595.2)	467.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	13.3	—	—	11.9	25.2
Fixed Income Securities:					
United States Government	—	1,267.0	—	—	1,267.0
Corporate Debt	—	123.3	—	—	123.3
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,392.0	—	—	1,392.0
Equity Securities – Domestic (b)	2,695.4	—	—	—	2,695.4
Total Spent Nuclear Fuel and Decommissioning Trusts	2,708.7	1,392.0	—	11.9	4,112.6
Total Assets	$ 2,965.0	$ 2,174.5	$ 276.2	$ (567.9)	$ 4,847.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 21.0	$ 688.4	$ 157.1	$ (520.3)	$ 346.2
Cash Flow Hedges:					
Commodity Hedges (c)	—	2.5	—	(1.3)	1.2
Interest Rate Hedges	—	1.7	—	—	1.7
Fair Value Hedges	—	114.8	—	—	114.8
Total Risk Management Liabilities	$ 21.0	$ 807.4	$ 157.1	$ (521.6)	$ 463.9

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2023

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

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 42.7	$ —	$ —	$ —	$ 42.7
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.2	—	2.3	2.5
Cash Flow Hedges:					
Interest Rate Hedges	—	2.3	—	(2.3)	—
Total Risk Management Assets	—	2.5	—	—	2.5
Total Assets	$ 42.7	$ 2.5	$ —	$ —	$ 45.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ —	$ 0.1	$ 0.1
Cash Flow Hedges:					
Interest Rate Hedges	—	0.1	—	(0.1)	—
Total Liabilities	$ —	$ 0.1	$ —	$ —	$ 0.1

December 31, 2023

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

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2024

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 8.4	$ —	$ —	$ —	$ 8.4
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	2.1	8.6	(2.0)	8.7
Total Assets	$ 8.4	$ 2.1	$ 8.6	$ (2.0)	$ 17.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 19.3	$ 4.6	$ (3.4)	$ 20.5

December 31, 2023

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

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2024

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 13.1	$ 1.8	$ (3.7)	$ 11.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	13.3	—	—	11.9	25.2
Fixed Income Securities:					
United States Government	—	1,267.0	—	—	1,267.0
Corporate Debt	—	123.3	—	—	123.3
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,392.0	—	—	1,392.0
Equity Securities - Domestic (b)	2,695.4	—	—	—	2,695.4
Total Spent Nuclear Fuel and Decommissioning Trusts	2,708.7	1,392.0	—	11.9	4,112.6
Total Assets	$ 2,708.7	$ 1,405.1	$ 1.8	$ 8.2	$ 4,123.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 7.6	$ 0.8	$ (7.7)	$ 0.7

December 31, 2023

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

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.1	$ —	$ —	$ 0.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 41.0	$ —	$ 41.0

December 31, 2023

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

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.1	$ 8.4	$ (0.6)	$ 7.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 31.2	$ 0.7	$ (0.6)	$ 31.3

December 31, 2023

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

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.1	$ 5.5	$ (0.3)	$ 5.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 11.1	$ 0.2	$ (0.2)	$ 11.1

December 31, 2023

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

(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, 2024 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 2024 and $(3) million in periods 2025-2027; Level 2 matures $(65) million in 2024, $51 million in periods 2025-2027 and $5 million in periods 2028-2029; Level 3 matures $34 million in 2024, $55 million in periods 2025-2027, $23 million in periods 2028-2029 and $(12) million in periods 2030-2032. 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, 2023 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(11) million in 2024 and $(4) million in 2025-2027; Level 2 matures $(99) million in 2024, $(44) million in periods 2025-2027, $7 million in periods 2028-2029 and $2 million in periods 2030-2033; Level 3 matures $74 million in 2024, $43 million in periods 2025-2027, $18 million in periods 2028-2029 and $(16) million in periods 2030-2033. Risk management commodity contracts are substantially comprised of power contracts.

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, 2024	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2023	$ 139.4	$ 22.4	$ 2.8	$ (50.6)	$ 18.6	$ 11.1
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	46.9	9.2	3.2	(0.4)	18.5	14.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	11.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	0.6	—	—	—	—	—
Settlements	(96.6)	(26.8)	(4.8)	2.6	(31.3)	(23.6)
Transfers into Level 3 (d) (e)	4.6	—	—	—	—	—
Transfers out of Level 3 (e)	2.1	—	—	—	—	0.5
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	10.8	(0.8)	(0.2)	7.4	1.9	2.6
Balance as of March 31, 2024	$ 119.1	$ 4.0	$ 1.0	$ (41.0)	$ 7.7	$ 5.3

Three Months Ended March 31, 2023	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2022	$ 160.4	$ 69.1	$ 4.6	$ (40.0)	$ 23.7	$ 14.2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(7.1)	(31.9)	1.2	(1.3)	16.6	12.9
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	14.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(13.9)	—	—	—	—	—
Settlements	(96.6)	(27.3)	(4.2)	1.0	(34.3)	(23.0)
Transfers into Level 3 (d) (e)	(6.1)	—	—	—	—	—
Transfers out of Level 3 (e)	1.0	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(7.4)	(4.2)	(0.5)	(6.6)	3.3	1.7
Balance as of March 31, 2023	$ 45.1	$ 5.7	$ 1.1	$ (46.9)	$ 9.3	$ 5.8

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Included in cash flow hedges on the statements of comprehensive income.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

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

Significant Unobservable Inputs
March 31, 2024

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (a)
		(in millions)						
AEP	Energy Contracts	$ 246.5	$ 146.1	Discounted Cash Flow	Forward Market Price (b)	$ 10.31	$ 169.47	$ 49.39
AEP	FTRs	29.7	11.0	Discounted Cash Flow	Forward Market Price (b)	(79.90)	23.79	(0.35)
APCo	FTRs	8.6	4.6	Discounted Cash Flow	Forward Market Price (b)	(0.38)	5.05	0.61
I&M	FTRs	1.8	0.8	Discounted Cash Flow	Forward Market Price (b)	0.03	6.82	0.84
OPCo	Energy Contracts	—	41.0	Discounted Cash Flow	Forward Market Price (b)	19.72	75.88	47.20
PSO	FTRs	8.4	0.7	Discounted Cash Flow	Forward Market Price (b)	(79.90)	3.13	(3.48)
SWEPCo	FTRs	5.5	0.2	Discounted Cash Flow	Forward Market Price (b)	(79.90)	3.13	(3.48)

December 31, 2023

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (a)
		(in millions)						
AEP	Energy Contracts	$ 225.5	$ 144.9	Discounted Cash Flow	Forward Market Price (b)	$ 5.21	$ 153.77	$ 45.05
AEP	Natural Gas Contracts	—	0.5	Discounted Cash Flow	Forward Market Price (c)	3.11	3.11	3.11
AEP	FTRs	68.6	9.3	Discounted Cash Flow	Forward Market Price (b)	(25.45)	17.07	—
APCo	FTRs	23.5	1.1	Discounted Cash Flow	Forward Market Price (b)	(1.04)	6.45	1.36
I&M	FTRs	4.5	1.7	Discounted Cash Flow	Forward Market Price (b)	(1.48)	8.40	(0.85)
OPCo	Energy Contracts	—	50.6	Discounted Cash Flow	Forward Market Price (b)	22.92	67.53	42.85
PSO	FTRs	19.7	1.1	Discounted Cash Flow	Forward Market Price (b)	(25.45)	4.80	(4.33)
SWEPCo	Natural Gas Contracts	—	0.5	Discounted Cash Flow	Forward Market Price (c)	3.11	3.11	3.11
SWEPCo	FTRs	12.0	0.4	Discounted Cash Flow	Forward Market Price (b)	(25.45)	4.80	(4.33)

(a) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.
(b) Represents market prices in dollars per MWh.
(c) Represents market prices in dollars per MMBtu.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrants as of March 31, 2024 and December 31, 2023:

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 2024 and 2023, adjusted for tax expense associated with certain discrete items. In the first quarter of 2024, I&M, PSO, and SWEPCo recorded tax benefits of $61 million, $49 million, and $114 million, respectively, related to the reduction of a regulatory liability associated with the IRS PLRs received, driving a reduction to the interim ETR resulting in AEP's tax rate of (16.5)% as shown below.

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

	Three Months Ended March 31, 2024							
	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	2.1 %	0.2 %	2.6 %	2.4 %	3.9 %	1.0 %	3.7 %	1.7 %
Tax Reform Excess ADIT Reversal	(2.3)%	(1.3)%	0.2 %	(13.4)%	(0.5)%	(6.0)%	(2.0)%	4.6 %
Remeasurement of Excess ADIT	(29.7)%	— %	— %	— %	(58.2)%	— %	(263.3)%	(224.7)%
Production and Investment Tax Credits	(6.8)%	(0.2)%	— %	(0.1)%	(1.1)%	— %	(49.6)%	(23.8)%
Flow Through	— %	0.1 %	0.3 %	(0.3)%	(2.8)%	0.6 %	0.2 %	0.6 %
AFUDC Equity	(1.2)%	(1.5)%	(1.8)%	(0.4)%	(0.7)%	(1.0)%	(1.3)%	(1.3)%
Discrete Tax Adjustments	0.2 %	— %	— %	— %	— %	— %	0.9 %	1.3 %
Other	0.2 %	0.5 %	— %	0.1 %	— %	0.2 %	1.2 %	(0.8)%
Effective Income Tax Rate	(16.5)%	18.8 %	22.3 %	9.3 %	(38.4)%	15.8 %	(289.2)%	(221.4)%

	Three Months Ended March 31, 2023							
	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	1.9 %	0.3 %	2.6 %	2.4 %	3.6 %	1.0 %	3.2 %	(0.4)%
Tax Reform Excess ADIT Reversal	(6.2)%	(1.5)%	0.3 %	(4.6)%	(7.9)%	(6.8)%	(18.7)%	(3.8)%
Production and Investment Tax Credits	(9.7)%	(0.2)%	— %	— %	(1.1)%	— %	(55.7)%	(26.4)%
Flow Through	0.1 %	0.2 %	0.3 %	0.6 %	(1.8)%	0.5 %	0.3 %	0.5 %
AFUDC Equity	(1.4)%	(1.5)%	(1.6)%	(0.7)%	(0.5)%	(0.8)%	(1.4)%	(0.8)%
Discrete Tax Adjustments	(3.2)%	— %	— %	3.2 %	1.8 %	— %	— %	— %
Other	0.1 %	0.1 %	0.1 %	— %	— %	— %	(2.0)%	(0.8)%
Effective Income Tax Rate	2.6 %	18.4 %	22.7 %	21.9 %	15.1 %	14.9 %	(53.3)%	(10.7)%

Federal and State Income Tax Audit Status

The statute of limitations for the IRS to examine AEP and subsidiaries originally filed federal return has expired for tax years 2016 and earlier. AEP has agreed to extend the statute of limitations on the 2017-2020 tax returns to May 31, 2025, to allow time for the current IRS audit to be completed including a refund claim approval by the Congressional Joint Committee on Taxation.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. AEP has received and agreed to immaterial IRS proposed adjustments on the 2017 tax return. The IRS exam is complete, and AEP is currently waiting on the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and AEP and subsidiaries are currently under examination in several state and local jurisdictions. Generally, the statutes of limitations have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Federal Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022, or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. As further significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, AEP will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

AEP and subsidiaries are applicable corporations for purposes of the CAMT in 2024. CAMT cash taxes are expected to be partially offset by regulatory recovery, the utilization of tax credits and additionally the cash inflow generated by the sale of tax credits. The sale of tax credits are presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP presents the loss on sale of tax credits through income tax expense.

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits. In 2023, AEP, on behalf of PSO, SWEPCo and AEP Energy Supply, LLC, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $174 million with $102 million received in 2023, $62 million received in the first quarter of 2024 and the remaining $10 million was received in April 2024. AEP expects to continue to explore the ability to efficiently monetize its tax credits through third party transferability agreements.

I&M's Cook Plant qualifies for the transferable Nuclear PTC, which is available for tax years beginning in 2024 through 2032. The Nuclear PTC is calculated based on electricity generated and sold to third-parties and is subject to a "reduction amount" as the facility's gross receipts increase above a certain threshold. Due to lack of guidance and uncertainty surrounding the computation of gross receipts, AEP and I&M are unable to estimate the amount of the Nuclear PTCs earned as of March 31, 2024 and have not included any Nuclear PTCs in the annualized effective tax rate for the first quarter of 2024.

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 2023, AEP filed a prospectus supplement and executed an Equity Distribution Agreement, pursuant to which AEP may sell, from time to time, up to an aggregate of $1.7 billion of its common stock through an ATM offering program, including an equity forward sales component. The compensation paid to the selling agents by AEP may be up to 2% of the gross offering proceeds of the shares. There were no issuances under the ATM program for the three months ended March 31, 2024.

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, 2024	December 31, 2023
	(in millions)	
Senior Unsecured Notes	$ 34,606.1	$ 33,779.4
Pollution Control Bonds	1,771.0	1,771.6
Notes Payable	163.5	193.3
Securitization Bonds	343.8	368.9
Spent Nuclear Fuel Obligation (a)	304.4	300.4
Junior Subordinated Notes	1,588.2	2,388.1
Other Long-term Debt	1,058.9	1,341.5
Total Long-term Debt Outstanding	39,835.9	40,143.2
Long-term Debt Due Within One Year	1,198.6	2,490.5
Long-term Debt	$ 38,637.3	$ 37,652.7

(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 $355 million and $348 million as of March 31, 2024 and December 31, 2023, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first three months of 2024 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEPTCo	Senior Unsecured Notes	$ 450.0	5.15	2034
APCo	Senior Unsecured Notes	400.0	5.65	2034
Non-Registrant:				
Transource Energy	Other Long-term Debt	18.0	Variable	2025
Total Issuances		$ 868.0		

(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	Junior Subordinated Notes	$ 805.0	2.03	2024
AEP Texas	Securitization Bonds	11.9	2.06	2025
APCo	Other Long-term Debt	300.0	Variable	2024
APCo	Securitization Bonds	13.4	3.77	2028
I&M	Notes Payable	1.2	Variable	2024
I&M	Notes Payable	0.9	Variable	2025
I&M	Notes Payable	4.0	0.93	2025
I&M	Notes Payable	5.0	3.44	2026
I&M	Notes Payable	6.8	5.93	2027
I&M	Notes Payable	6.8	6.01	2028
I&M	Other Long-term Debt	0.7	6.00	2025
PSO	Other Long-term Debt	0.1	3.00	2027
Non-Registrant:				
AEGCo	Notes Payable	5.0	2.43	2028
Transource Energy	Senior Unsecured Notes	1.4	2.75	2050
Total Retirements and Principal Payments		$ 1,162.2		

Long-term Debt Subsequent Events

In April 2024, APCo remarketed $86 million of Pollution Control Bonds.

In April 2024, I&M issued $80 million of 6.41% Notes Payable due in 2028.

In April 2024, I&M retired $8 million of Notes Payable related to DCC Fuel.

In April 2024, WPCo issued $450 million of 6.89% Notes Payable due in 2034.

In April 2024, WPCo retired $265 million of Other Long-term Debt.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 0.2% of consolidated tangible net assets as of March 31, 2024. 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 requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to APCo and I&M.

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

The 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 (Applies to all Registrant Subsidiaries)

AEP subsidiaries use a corporate borrowing program to meet their short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of March 31, 2024 and December 31, 2023 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2024 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of March 31, 2024	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 267.9	$ —	$ 191.2	$ —	$ (267.9)	$ 600.0	
AEPTCo	313.3	298.0	178.5	75.3	272.9	820.0	(a)
APCo	399.5	51.1	205.5	20.3	37.4	750.0	
I&M	125.5	—	60.2	—	(73.2)	500.0	
OPCo	295.2	—	143.4	—	(295.2)	500.0	
PSO	264.6	—	128.8	—	(264.6)	750.0	
SWEPCo	254.5	—	161.1	—	(254.5)	750.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of March 31, 2024 and December 31, 2023 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the three months ended March 31, 2024 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, 2024
		(in millions)	
AEP Texas	$ 7.1	$ 7.0	$ 7.0
SWEPCo	2.3	2.2	2.3

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of borrowings from AEP as of March 31, 2024 and December 31, 2023 are included in Advances from Affiliates on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limit for the three months ended March 31, 2024 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, 2024	Loans to AEP as of March 31, 2024	Authorized Short-term Borrowing Limit	
				(in millions)			
$ 44.4	$ 148.5	$ 4.4	$ 72.9	$ 3.7	$ —	$ 50.0	(a)

(a) Amount represents the authorized short-term borrowing limit from FERC or state regulatory agencies not otherwise included in the utility money pool above.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Three Months Ended March 31,	
	2024	2023
Maximum Interest Rate	5.79 %	5.42 %
Minimum Interest Rate	5.66 %	4.66 %

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

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Three Months Ended March 31,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Three Months Ended March 31,	
Company	2024	2023	2024	2023
AEP Texas	5.71 %	5.18 %	— %	— %
AEPTCo	5.72 %	5.09 %	5.70 %	5.29 %
APCo	5.74 %	5.14 %	5.72 %	5.12 %
I&M	5.73 %	5.12 %	— %	5.16 %
OPCo	5.71 %	5.17 %	— %	— %
PSO	5.71 %	4.84 %	— %	5.11 %
SWEPCo	5.71 %	5.12 %	— %	— %

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, 2024			Three Months Ended March 31, 2023		
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	5.79 %	5.66 %	5.72 %	5.42 %	4.66 %	5.12 %
SWEPCo	5.79 %	5.66 %	5.72 %	5.42 %	4.66 %	5.13 %

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
2024	5.79 %	5.66 %	5.79 %	5.66 %	5.74 %	5.71 %
2023	5.38 %	4.53 %	5.38 %	4.53 %	5.03 %	5.15 %

Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		March 31, 2024		December 31, 2023	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(dollars in millions)			
AEP	Securitized Debt for Receivables (b)	$ 900.0	5.54 %	$ 888.0	5.65 %
AEP	Commercial Paper	2,832.2	5.61 %	1,937.9	5.69 %
SWEPCo	Notes Payable	5.4	7.68 %	4.3	7.71 %
	Total Short-term Debt	$ 3,737.6		$ 2,830.2	

(a) Weighted-average rate as of March 31, 2024 and December 31, 2023, respectively.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Credit Facilities

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

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

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

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables and expires in September 2025. As of March 31, 2024, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended March 31, 2024	Three Months Ended March 31, 2023
	(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	5.61 %	4.86 %
Net Uncollectible Accounts Receivable Written-Off	$ 8.1	$ 6.9

	March 31, 2024	December 31, 2023
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,164.2	$ 1,207.4
Short-term – Securitized Debt of Receivables	900.0	888.0
Delinquent Securitized Accounts Receivable	58.2	52.2
Bad Debt Reserves Related to Securitization	42.6	42.0
Unbilled Receivables Related to Securitization	336.9	409.8

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

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

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

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

Company	March 31, 2024	December 31, 2023
	(in millions)	
APCo	$ 196.5	$ 184.6
I&M	167.0	156.4
OPCo	536.0	541.7
PSO	96.3	134.6
SWEPCo	144.2	168.3

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

	Three Months Ended March 31,	
Company	2024	2023
	(in millions)	
APCo	$ 4.2	$ 4.9
I&M	4.1	3.9
OPCo	7.4	7.3
PSO	3.4	3.2
SWEPCo	4.8	4.3

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

	Three Months Ended March 31,	
Company	2024	2023
	(in millions)	
APCo	$ 536.0	$ 506.2
I&M	529.7	525.4
OPCo	845.7	884.4
PSO	361.6	416.3
SWEPCo	425.4	437.6

13. VARIABLE INTEREST ENTITIES

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

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

AEP holds ownership interests in businesses with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE, and if so, whether or not the VIE should be consolidated into AEP's financial statements. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. If an entity is determined not to be a VIE, or if the entity is determined to be a VIE and AEP is not deemed to be the primary beneficiary, the entity is accounted for under the equity method of accounting.

Consolidated Variable Interests Entities

The Annual Report on Form 10-K for the year ended December 31, 2023 includes a detailed discussion of the Registrants' consolidated VIEs.

The balances below represent the assets and liabilities of consolidated VIEs. These balances include intercompany transactions that are eliminated upon consolidation.

March 31, 2024

	Consolidated VIEs							
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$ 5.1	$ 75.3	$ 40.1	$ 20.4	$ 6.3	$ 1,165.3	$ 211.6	$ 31.7
Net Property, Plant and Equipment	—	129.5	—	—	—	—	—	536.9
Other Noncurrent Assets	140.1	63.5	55.3 (a)	139.7 (b)	130.3 (c)	10.2	—	9.3
Total Assets	$ 145.2	$ 268.3	$ 95.4	$ 160.1	$ 136.6	$ 1,175.5	$ 211.6	$ 577.9
LIABILITIES AND EQUITY								
Current Liabilities	$ 22.8	$ 75.1	$ 76.3	$ 36.4	$ 29.0	$ 1,113.7	$ 52.3	$ 22.5
Noncurrent Liabilities	122.1	193.2	14.7	122.4	105.7	1.0	90.8	258.8
Equity	0.3	—	4.4	1.3	1.9	60.8	68.5	296.6
Total Liabilities and Equity	$ 145.2	$ 268.3	$ 95.4	$ 160.1	$ 136.6	$ 1,175.5	$ 211.6	$ 577.9

(a) Includes an intercompany item eliminated in consolidation of $6 million.
(b) Includes an intercompany item eliminated in consolidation of $6 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

December 31, 2023

	Consolidated VIEs							
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$ 4.2	$ 81.9	$ 25.5	$ 27.5	$ 13.3	$ 1,208.8	$ 205.3	$ 36.9
Net Property, Plant and Equipment	—	153.8	—	—	—	—	—	533.4
Other Noncurrent Assets	150.7	81.7	71.4 (a)	145.6 (b)	138.2 (c)	9.6	—	5.1
Total Assets	$ 154.9	$ 317.4	$ 96.9	$ 173.1	$ 151.5	$ 1,218.4	$ 205.3	$ 575.4
LIABILITIES AND EQUITY								
Current Liabilities	$ 19.9	$ 81.7	$ 75.5	$ 36.8	$ 29.9	$ 1,155.0	$ 49.2	$ 45.3
Noncurrent Liabilities	134.8	235.7	17.0	135.1	119.7	0.9	91.7	241.5
Equity	0.2	—	4.4	1.2	1.9	62.5	64.4	288.6
Total Liabilities and Equity	$ 154.9	$ 317.4	$ 96.9	$ 173.1	$ 151.5	$ 1,218.4	$ 205.3	$ 575.4

(a) Includes an intercompany item eliminated in consolidation of $8 million.
(b) Includes an intercompany item eliminated in consolidation of $6 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

Significant Variable Interests in Non-Consolidated VIEs and Significant Equity Method Investments

The Annual Report on Form 10-K for the year ended December 31, 2023 includes a detailed discussion of significant variable interests in non-consolidated VIEs and other significant equity method investments. As of December 31, 2023, AEP no longer owns interests in four joint ventures due to the sale of the Competitive Contracted Renewables Portfolio. Previously held by AEP Wind Holdings, LLC, the interests were accounted for under the equity method. See the "Disposition of the Competitive Contracted Renewables Portfolio" 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, 2024						
	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	$ 1,212.3	$ 703.8	$ —	$ —	$ —	$ —	$ 1,916.1
Commercial Revenues	645.1	397.0	—	—	—	—	1,042.1
Industrial Revenues (a)	647.1	136.1	—	—	—	(0.2)	783.0
Other Retail Revenues	55.3	13.9	—	—	—	—	69.2
Total Retail Revenues	2,559.8	1,250.8	—	—	—	(0.2)	3,810.4
Wholesale and Competitive Retail Revenues:							
Generation Revenues	235.9	—	—	27.4	—	0.1	263.4
Transmission Revenues (b)	118.9	179.8	488.7	—	—	(418.6)	368.8
Renewable Generation Revenues (a)	—	—	—	6.3	—	(1.4)	4.9
Retail, Trading and Marketing Revenues (c)	—	—	—	571.4	0.5	(46.2)	525.7
Total Wholesale and Competitive Retail Revenues	354.8	179.8	488.7	605.1	0.5	(466.1)	1,162.8
Other Revenues from Contracts with Customers (d)	59.7	51.0	8.1	1.3	60.4	(68.7)	111.8
Total Revenues from Contracts with Customers	2,974.3	1,481.6	496.8	606.4	60.9	(535.0)	5,085.0
Other Revenues:							
Alternative Revenue Programs (e)	(0.7)	0.7	0.5	—	—	1.0	1.5
Other Revenues (a) (f)	(25.7)	7.9	—	(42.9)	(8.1)	8.0	(60.8)
Total Other Revenues	(26.4)	8.6	0.5	(42.9)	(8.1)	9.0	(59.3)
Total Revenues	$ 2,947.9	$ 1,490.2	$ 497.3	$ 563.5	$ 52.8	$ (526.0)	$ 5,025.7

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $387 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $46 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $48 million. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(f) Generation & Marketing includes economic hedge activity.

	Three Months Ended March 31, 2023						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,170.4	$ 656.8	$ —	$ —	$ —	$ —	$ 1,827.2
Commercial Revenues	633.4	375.9	—	—	—	—	1,009.3
Industrial Revenues	670.3	212.9	—	—	—	(0.2)	883.0
Other Retail Revenues	56.8	12.1	—	—	—	—	68.9
Total Retail Revenues	2,530.9	1,257.7	—	—	—	(0.2)	3,788.4
Wholesale and Competitive Retail Revenues:							
Generation Revenues	182.8	—	—	32.4	—	—	215.2
Transmission Revenues (a)	114.7	164.2	450.1	—	—	(401.8)	327.2
Renewable Generation Revenues (b)	—	—	—	21.3	—	(0.1)	21.2
Retail, Trading and Marketing Revenues (b)	—	—	—	413.7	(0.3)	0.1	413.5
Total Wholesale and Competitive Retail Revenues	297.5	164.2	450.1	467.4	(0.3)	(401.8)	977.1
Other Revenues from Contracts with Customers (c)	32.6	42.8	3.6	0.6	29.4	(43.7)	65.3
Total Revenues from Contracts with Customers	2,861.0	1,464.7	453.7	468.0	29.1	(445.7)	4,830.8
Other Revenues:							
Alternative Revenue Programs (d)	(3.1)	(11.6)	1.8	—	—	2.9	(10.0)
Other Revenues (b) (e)	(0.1)	11.1	—	(141.0)	1.0	(0.9)	(129.9)
Total Other Revenues	(3.2)	(0.5)	1.8	(141.0)	1.0	2.0	(139.9)
Total Revenues	$ 2,857.8	$ 1,464.2	$ 455.5	$ 327.0	$ 30.1	$ (443.7)	$ 4,690.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $357 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 Corporate and Other was $29 million. The remaining affiliated amounts were immaterial.

(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(e) Generation & Marketing includes economic hedge activity.

	Three Months Ended March 31, 2024						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 147.3	$ —	$ 526.3	$ 224.8	$ 556.5	$ 158.2	$ 182.4
Commercial Revenues	110.9	—	188.3	144.8	286.1	103.0	140.0
Industrial Revenues (a)	35.6	—	196.4	147.9	100.5	80.3	95.0
Other Retail Revenues	9.7	—	28.1	1.3	4.2	21.5	2.6
Total Retail Revenues	303.5	—	939.1	518.8	947.3	363.0	420.0
Wholesale Revenues:							
Generation Revenues (b)	—	—	85.1	137.3	—	2.2	47.1
Transmission Revenues (c)	155.9	475.4	47.1	10.1	23.8	10.8	39.6
Total Wholesale Revenues	155.9	475.4	132.2	147.4	23.8	13.0	86.7
Other Revenues from Contracts with Customers (d)	8.8	8.1	21.7	27.6	42.2	12.0	9.6
Total Revenues from Contracts with Customers	468.2	483.5	1,093.0	693.8	1,013.3	388.0	516.3
Other Revenues:							
Alternative Revenue Programs (e)	(1.8)	(0.7)	(0.1)	(0.5)	2.6	(0.2)	(0.1)
Other Revenues (a)	—	—	0.1	(25.9)	7.9	—	—
Total Other Revenues	(1.8)	(0.7)	—	(26.4)	10.5	(0.2)	(0.1)
Total Revenues	$ 466.4	$ 482.8	$ 1,093.0	$ 667.4	$ 1,023.8	$ 387.8	$ 516.2

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $41 million primarily related to the PPA with KGPCo.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $384 million, APCo was $21 million and SWEPCo was $14 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $18 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

	Three Months Ended March 31, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 130.7	$ —	$ 470.5	$ 239.6	$ 526.0	$ 170.9	$ 175.9
Commercial Revenues	97.3	—	171.3	138.9	278.5	109.1	143.5
Industrial Revenues	39.3	—	185.8	152.6	173.6	98.3	104.2
Other Retail Revenues	8.3	—	26.2	1.3	3.8	24.2	2.6
Total Retail Revenues	275.6	—	853.8	532.4	981.9	402.5	426.2
Wholesale Revenues:							
Generation Revenues (a)	—	—	80.2	104.0	—	0.9	39.6
Transmission Revenues (b)	146.3	438.7	41.4	8.1	17.9	11.3	42.9
Total Wholesale Revenues	146.3	438.7	121.6	112.1	17.9	12.2	82.5
Other Revenues from Contracts with Customers (c)	9.7	3.7	13.0	21.4	33.2	2.3	7.9
Total Revenues from Contracts with Customers	431.6	442.4	988.4	665.9	1,033.0	417.0	516.6
Other Revenues:							
Alternative Revenue Programs (d)	(2.1)	(0.8)	(0.7)	(2.9)	(9.5)	—	(0.7)
Other Revenues (e)	—	—	—	—	11.1	—	—
Total Other Revenues	(2.1)	(0.8)	(0.7)	(2.9)	1.6	—	(0.7)
Total Revenues	$ 429.5	$ 441.6	$ 987.7	$ 663.0	$ 1,034.6	$ 417.0	$ 515.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $47 million primarily related to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $349 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $18 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations (Applies to AEP, APCo and I&M)

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of March 31, 2024. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrants elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2024	2025-2026	2027-2028	After 2028	Total
			(in millions)		
AEP	$ 62.3	$ 166.8	$ 84.1	$ 24.7	$ 337.9
APCo	12.1	32.2	24.3	11.7	80.3
I&M	3.3	8.8	8.8	4.5	25.4

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, 2024 and December 31, 2023.

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, 2024 and December 31, 2023.

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, 2024 and December 31, 2023. 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:

	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
March 31, 2024	$ —	$ 129.2	$ 77.8	$ 55.8	$ 72.3	$ 10.8	$ 16.1
December 31, 2023	—	123.2	71.7	44.0	70.1	12.4	27.4

CONTROLS AND PROCEDURES

During the first quarter of 2024, 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, 2024, 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 2024 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. <u>Legal Proceedings</u>

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

Item 1A. <u>Risk Factors</u>

The Annual Report on Form 10-K for the year ended December 31, 2023 includes a detailed discussion of risk factors. As of March 31, 2024, the risk factors appearing in AEP’s 2023 Annual Report are supplemented and updated as follows:

The occurrence of one or more wildfires could cause tremendous loss, impact the market value and credit ratings of our securities and have a material adverse effect on our financial condition. (Applies to all Registrants)

More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. AEP’s infrastructure is aging and poses risks to safety and system reliability and wildfire mitigation initiatives may not be successful or effective in preventing or reducing wildfire-related events. Wildfires can occur even when effective mitigation procedures are followed. Despite AEP’s wildfire mitigation initiatives, a wildfire could be ignited, spread and cause damages, which would subject AEP to significant liability. Other potential risks associated with wildfires include the inability to secure sufficient insurance coverage, or increased costs of insurance, regulatory recovery risk, litigation risk, and the potential for a credit downgrade and subsequent additional costs to access capital markets.

Item 2. <u>Unregistered Sales of Equity Securities and Use of Proceeds</u>

None.

Item 3. <u>Defaults Upon Senior Securities</u>

None.

Item 4. <u>Mine Safety Disclosures</u>

Not applicable.

Item 5. <u>Other Information</u>

On March 1, 2024, Greg B. Hall, the Executive Vice President and Chief Commercial Officer of the Company, entered into a Rule 10b5-1 trading agreement (“Rule 10b5-1 Trading Plan”) intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Securities Exchange Act of 1934. Mr. Hall’s Rule 10b5-1 Trading Plan provides for an aggregate sale of up to 3,297 shares of common stock on or after May 31, 2024 and until such shares are sold and 2,703 shares of common stock between May 31, 2024 and December 31, 2024.

On March 1, 2024, Therace M. Risch, the Executive Vice President and Chief Information and Technology Officer of the Company, entered into a Rule 10b5-1 Trading Plan intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Securities Exchange Act of 1934. Ms. Risch’s Rule 10b5-1 Trading Plan provides for an aggregate sale of up to 5,539 shares of common stock between May 31, 2024 and April 30, 2025.

On March 5, 2024, Antonio P. Smyth, Executive Vice President – Grid Solutions and Government Affairs of the Company, entered into a Rule 10b5-1 Trading Plan intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Securities Exchange Act of 1934. Mr. Smyth’s Rule 10b5-1 Trading Plan provides for an aggregate sale of up to 2,623 shares of common stock on or after June 5, 2024 and until such shares are sold and 2,624 shares of common stock between June 5, 2024 and January 31, 2025.

During the three months ended March 31, 2024, none of the Company’s other directors or officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K of the Securities Act of 1933).

Item 6. Exhibits

The documents designated with an (*) below have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof.

Exhibit	Description	Previously Filed as Exhibit to:
AEPTCo‡ File No. 333-217143		
4(a)	Company Order and Officer's Certificate between AEPTCo and The Bank of New York Mellon Trust Company, N.A. as Trustee dated March 13, 2024 establishing terms of the 5.15% Senior Notes, Series Q due 2034.	Form 8-K dated March 13, 2024, Exhibit 4(a)
APCo‡ File No. 1-3457		
4(b)	Company Order and Officer's Certificate between APCo and The Bank of New York Mellon Trust Company, N.A. as Trustee dated March 20, 2024 establishing terms of the 5.65% Senior Notes, Series CC due 2034.	Form 8-K dated March 20, 2024, Exhibit 4(a)

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
4(c)	March 28, 2024 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(d)	March 28, 2024 Amendment and extension to $5,000,000,000 of the $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							
10(a)	Executive Severance, Release of All Claims and Noncompetition Agreement between the Company and Julia A. Sloat.	X							
10(b)	Aircraft Time Sharing Agreement between AEPSC and Benjamin G.S. Fowke, III.	X							
10(c)	American Electric Power System 2024 Long-Term Incentive Plan.	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
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

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
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/ Kate Sturgess
Kate Sturgess
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/ Kate Sturgess
Kate Sturgess
Controller and Chief Accounting Officer

Date: April 30, 2024

APPENDIX 8

EVERGY 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, 2024

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **March 31, 2024**

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	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
001-38515	**EVERGY, INC.** (a Missouri corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	82-2733395
001-03523	**EVERGY KANSAS CENTRAL, INC.** (a Kansas corporation) 818 South Kansas Avenue Topeka, Kansas 66612 (785) 575-6300	48-0290150
000-51873	**EVERGY METRO, INC.** (a Missouri corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Evergy, Inc. common stock	EVRG	The Nasdaq Stock Market LLC

Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Evergy, Inc.	Yes	☒	No	☐
Evergy Kansas Central, Inc.	Yes	☒	No	☐
Evergy Metro, Inc.	Yes	☒	No	☐

Indicate by check mark whether the registrant has 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 registrant was required to submit such files).

Evergy, Inc.	Yes	☒	No	☐
Evergy Kansas Central, Inc.	Yes	☒	No	☐
Evergy Metro, Inc.	Yes	☒	No	☐

Indicate by check mark whether the registrant 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.

Evergy, Inc.	Large Accelerated Filer	☒	Accelerated Filer	☐	Non-accelerated Filer	☐	Smaller Reporting Company	☐	Emerging Growth Company	☐
Evergy Kansas Central, Inc.	Large Accelerated Filer	☐	Accelerated Filer	☐	Non-accelerated Filer	☒	Smaller Reporting Company	☐	Emerging Growth Company	☐
Evergy Metro, Inc.	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 registrant has 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.

Evergy, Inc.	☐
Evergy Kansas Central, Inc.	☐
Evergy Metro, Inc.	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Evergy, Inc.	Yes	☐	No	☒
Evergy Kansas Central, Inc.	Yes	☐	No	☒
Evergy Metro, Inc.	Yes	☐	No	☒

On May 3, 2024, Evergy, Inc. had 229,929,116 shares of common stock outstanding. On May 3, 2024, Evergy Metro, Inc. and Evergy Kansas Central, Inc. each had one share of common stock outstanding and held by Evergy, Inc.

Evergy Kansas Central, Inc. and Evergy Metro, Inc. 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.

This combined Quarterly Report on Form 10-Q is provided by the following registrants: Evergy, Inc. (Evergy), Evergy Kansas Central, Inc. (Evergy Kansas Central) and Evergy Metro, Inc. (Evergy Metro) (collectively, the Evergy Companies). Information relating to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrants.

This report should be read in its entirety. No one section of the report deals with all aspects of the subject matter. It should be read in conjunction with the consolidated financial statements and related notes and with the management's discussion and analysis of financial condition and results of operations included in the annual report on Form 10-K for the fiscal year ended December 31, 2023 for each of Evergy, Evergy Kansas Central and Evergy Metro (2023 Form 10-K).

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CAUTIONARY STATEMENTS REGARDING CERTAIN FORWARD-LOOKING INFORMATION
Statements made in this document that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, statements relating to Evergy's strategic plan, including, without limitation, those related to earnings per share, dividend, operating and maintenance expense and capital investment goals; the outcome of legislative efforts and regulatory and legal proceedings; future energy demand; future power prices; plans with respect to existing and potential future generation resources; the availability and cost of generation resources and energy storage; target emissions reductions; and other matters relating to expected financial performance or affecting future operations. Forward-looking statements are often accompanied by forward-looking words such as "anticipates," "believes," "expects," "estimates," "forecasts," "should," "could," "may," "seeks," "intends," "proposed," "projects," "planned," "target," "outlook," "remain confident," "goal," "will" or other words of similar meaning. Forward-looking statements involve risks, uncertainties and other factors that could cause actual results to differ materially from the forward-looking information.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, the Evergy Companies are providing a number of risks, uncertainties and other factors that could cause actual results to differ from the forward-looking information. These risks, uncertainties and other factors include, but are not limited to: economic and weather conditions and any impact on sales, prices and costs; changes in business strategy or operations; the impact of federal, state and local political, legislative, judicial and regulatory actions or developments, including deregulation, re-regulation, securitization and restructuring of the electric utility industry; decisions of regulators regarding, among other things, customer rates and the prudency of operational decisions such as capital expenditures and asset retirements; changes in applicable laws, regulations, rules, principles or practices, or the interpretations thereof, governing tax, accounting and environmental matters, including air and water quality and waste management and disposal; the impact of climate change, including increased frequency and severity of significant weather events and the extent to which counterparties are willing to do business with, finance the operations of or purchase energy from the Evergy Companies due to the fact that the Evergy Companies operate coal-fired generation; prices and availability of electricity and natural gas in wholesale markets; market perception of the energy industry and the Evergy Companies; the impact of future pandemic health events on, among other things, sales, results of operations, financial position, liquidity and cash flows, and also on operational issues, such as supply chain issues and the availability and ability of the Evergy Companies' employees and suppliers to perform the functions that are necessary to operate the Evergy Companies; changes in the energy trading markets in which the Evergy Companies participate, including retroactive repricing of transactions by regional transmission organizations (RTO) and independent system operators; financial market conditions and performance, disruptions in the banking industry, including volatility in interest rates and credit spreads and in availability and cost of capital and the effects on derivatives and hedges, nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments; impact of physical and cybersecurity breaches, criminal activity, terrorist attacks, acts of war and other disruptions to the Evergy Companies' facilities or information technology infrastructure or the facilities and infrastructure of third-party service providers on which the Evergy Companies rely; impact of geopolitical conflicts on the global energy market; ability to carry out marketing and sales plans; cost, availability, quality and timely provision of equipment, supplies, labor and fuel; impacts of tariffs; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; delays and cost increases of generation, transmission, distribution or other projects; the Evergy Companies' ability to manage their transmission and distribution development plans and transmission joint ventures; the inherent risks associated with the ownership and operation of a nuclear facility, including environmental, health, safety, regulatory and financial risks; workforce risks, including those related to the Evergy Companies' ability to attract and retain qualified personnel, maintain satisfactory relationships with their labor unions and manage costs of, or changes in, wages, retirement, health care and other benefits; disruption, costs and uncertainties caused by or related to the actions of individuals or entities, such as activist shareholders or special interest groups, that seek to influence Evergy's strategic plan, financial results or operations; the impact of changing expectations and demands of the Evergy Companies' customers, regulators, investors and stakeholders, including heightened emphasis on environmental, social and governance concerns; the possibility that strategic initiatives, including mergers, acquisitions and divestitures, and long-term financial plans, may not create the value that they are expected to achieve in a timely manner or at all; difficulties in maintaining relationships with customers, employees, regulators or suppliers; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. You should also carefully consider the information contained in the Evergy Companies' other filings with the Securities and Exchange Commission (SEC). Additional risks and uncertainties are discussed from time to time in current, quarterly and annual reports filed by the Evergy Companies with the SEC. New factors emerge from time to time, and it's not possible for the Evergy Companies to predict all such factors, nor can the Evergy Companies assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained or implied in any forward-looking statement. Given these uncertainties, undue reliance should not be placed on these forward-looking statements. The Evergy Companies undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

AVAILABLE INFORMATION

The SEC maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at sec.gov. Additionally, information about the Evergy Companies, including their combined annual reports on Form 10-K, combined quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with the SEC, is also available through the Evergy Companies' website, http://investors.evergy.com. Such reports are accessible at no charge and are made available as soon as reasonably practical after such material is filed with or furnished to the SEC.

Investors should note that the Evergy Companies announce material financial information in SEC filings, press releases and public conference calls. In accordance with SEC guidelines, the Evergy Companies also use the Investor Relations section of their website, http://investors.evergy.com, to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on the Evergy Companies' website is not part of this document.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report.

Abbreviation or Acronym	Definition
AEP	American Electric Power Company, Inc.
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
AROs	Asset retirement obligations
CAA	Clean Air Act
CCN	Certificate of Convenience and Necessity
CCRs	Coal combustion residuals
CO_2	Carbon dioxide
COLI	Corporate-owned life insurance
CSAPR	Cross-State Air Pollution
Dogwood	Dogwood Energy Center
ELG	Effluent limitations guidelines
EPA	Environmental Protection Agency
EPS	Earnings per common share
ERISA	Employee Retirement Income Security Act of 1974, as amended
Evergy	Evergy, Inc. and its consolidated subsidiaries
Evergy Board	Evergy Board of Directors
Evergy Companies	Evergy, Evergy Kansas Central, and Evergy Metro, collectively, which are individual registrants within the Evergy consolidated group
Evergy Kansas Central	Evergy Kansas Central, Inc., a wholly-owned subsidiary of Evergy, and its consolidated subsidiaries
Evergy Kansas South	Evergy Kansas South, Inc., a wholly-owned subsidiary of Evergy Kansas Central
Evergy Metro	Evergy Metro, Inc., a wholly-owned subsidiary of Evergy, and its consolidated subsidiaries
Evergy Missouri West	Evergy Missouri West, Inc., a wholly-owned subsidiary of Evergy
Evergy Missouri West Storm Funding	Evergy Missouri West Storm Funding I, LLC
Evergy Transmission Company	Evergy Transmission Company, LLC
Exchange Act	The Securities Exchange Act of 1934, as amended
February 2021 winter weather event	Significant winter weather event in February 2021 that resulted in extremely cold temperatures over a multi-day period across much of the central and southern United States
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
Great Plains Energy	Great Plains Energy Incorporated
ITFIP	Interstate Transport Federal Implementation Plans
ITSIP	Interstate Transport State Implementation Plans
JEC	Jeffrey Energy Center
KCC	State Corporation Commission of the State of Kansas
KDHE	Kansas Department of Health & Environment

Abbreviation or Acronym	Definition
kV	Kilovolt
MDNR	Missouri Department of Natural Resources
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NAV	Net asset value
OCI	Other comprehensive income
Prairie Wind	Prairie Wind Transmission, LLC, 50% owned by Evergy Kansas Central
RSU	Restricted share unit
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
SIP	State implementation plan
SPP	Southwest Power Pool, Inc.
TCR	Transmission congestion right
TDC	Transmission delivery charge
TFR	Transmission formula rate
Transource	Transource Energy, LLC and its subsidiaries, 13.5% owned by Evergy Transmission Company
VIE	Variable interest entity
Wolf Creek	Wolf Creek Generating Station

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

EVERGY, INC.
Consolidated Balance Sheets
(Unaudited)

	March 31 2024	December 31 2023
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 63.7	$ 27.7
Receivables, net of allowance for credit losses of $18.5 and $24.2, respectively	175.3	256.9
Accounts receivable pledged as collateral	362.0	342.0
Fuel inventory and supplies	800.7	776.2
Income taxes receivable	—	11.5
Regulatory assets, includes $15.2 and $— related to variable interest entity, respectively	330.1	292.1
Prepaid expenses	62.3	51.3
Other assets	32.4	31.4
Total Current Assets	1,826.5	1,789.1
PROPERTY, PLANT AND EQUIPMENT, NET, includes $131.8 and $133.6 related to variable interest entity, respectively	23,945.7	23,728.7
OTHER ASSETS:		
Regulatory assets, includes $306.5 and $— related to variable interest entity, respectively	1,758.6	1,795.3
Nuclear decommissioning trust fund	805.9	766.4
Goodwill	2,336.6	2,336.6
Other	583.0	560.0
Total Other Assets	5,484.1	5,458.3
TOTAL ASSETS	$ 31,256.3	$ 30,976.1

The accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Balance Sheets
(Unaudited)

	March 31 2024	December 31 2023
LIABILITIES AND EQUITY	(millions, except share amounts)	
CURRENT LIABILITIES:		
Current maturities of long-term debt, includes $11.5 and $— related to variable interest entity, respectively	**$ 811.5**	$ 800.0
Commercial paper	**798.7**	951.8
Collateralized note payable	**362.0**	342.0
Accounts payable	**356.7**	616.9
Accrued taxes	**264.5**	156.7
Accrued interest	**177.0**	134.2
Regulatory liabilities	**152.7**	183.0
Asset retirement obligations	**42.6**	40.3
Accrued compensation and benefits	**56.8**	74.5
Other	**167.4**	213.2
Total Current Liabilities	**3,189.9**	3,512.6
LONG-TERM LIABILITIES:		
Long-term debt, net, includes $311.5 and $— related to variable interest entity, respectively	**11,658.4**	11,053.3
Deferred income taxes	**2,117.2**	2,097.9
Unamortized investment tax credits	**168.2**	170.0
Regulatory liabilities	**2,522.1**	2,542.5
Pension and post-retirement liability	**475.4**	464.1
Asset retirement obligations	**1,169.7**	1,162.8
Other	**291.3**	287.9
Total Long-Term Liabilities	**18,402.3**	17,778.5
Commitments and Contingencies (Note 10)		
EQUITY:		
Evergy, Inc. Shareholders' Equity:		
Common stock - 600,000,000 shares authorized, without par value 229,922,338 and 229,729,296 shares issued, stated value	**7,235.0**	7,234.9
Retained earnings	**2,432.4**	2,457.8
Accumulated other comprehensive loss	**(28.3)**	(29.6)
Total Evergy, Inc. Shareholders' Equity	**9,639.1**	9,663.1
Noncontrolling Interests	**25.0**	21.9
Total Equity	**9,664.1**	9,685.0
TOTAL LIABILITIES AND EQUITY	**$ 31,256.3**	$ 30,976.1

The accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Statements of Comprehensive Income
(Unaudited)

Three Months Ended March 31	2024	2023
	(millions, except per share amounts)	
OPERATING REVENUES	$ 1,331.0	$ 1,296.8
OPERATING EXPENSES:		
Fuel and purchased power	376.4	354.2
SPP network transmission costs	72.7	81.2
Operating and maintenance	231.5	216.3
Depreciation and amortization	276.1	263.4
Taxes other than income tax	114.1	102.4
Total Operating Expenses	1,070.8	1,017.5
INCOME FROM OPERATIONS	260.2	279.3
OTHER INCOME (EXPENSE):		
Investment earnings	5.3	9.1
Other income	8.5	12.2
Other expense	(9.5)	(21.3)
Total Other Income, Net	4.3	—
Interest expense	133.2	123.1
INCOME BEFORE INCOME TAXES	131.3	156.2
Income tax expense	7.3	12.4
Equity in earnings of equity method investees, net of income taxes	1.8	1.9
NET INCOME	125.8	145.7
Less: Net income attributable to noncontrolling interests	3.1	3.1
NET INCOME ATTRIBUTABLE TO EVERGY, INC.	$ 122.7	$ 142.6
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO EVERGY, INC. (see Note 1)		
Basic earnings per common share	$ 0.53	$ 0.62
Diluted earnings per common share	$ 0.53	$ 0.62
AVERAGE COMMON SHARES OUTSTANDING		
Basic	230.2	230.0
Diluted	230.4	230.3
COMPREHENSIVE INCOME		
NET INCOME	$ 125.8	$ 145.7
Derivative hedging activity		
Reclassification to expenses, net of tax	1.3	1.3
Derivative hedging activity, net of tax	1.3	1.3
Total other comprehensive income	1.3	1.3
COMPREHENSIVE INCOME	127.1	147.0
Less: Comprehensive income attributable to noncontrolling interest	3.1	3.1
COMPREHENSIVE INCOME ATTRIBUTABLE TO EVERGY, INC.	$ 124.0	$ 143.9

The accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Statements of Cash Flows
(Unaudited)

Three Months Ended March 31	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:	(millions)	
Net income	$ 125.8	$ 145.7
Adjustments to reconcile income to net cash from operating activities:		
Depreciation and amortization	276.1	263.4
Amortization of nuclear fuel	15.7	15.1
Amortization of deferred refueling outage	4.6	4.6
Amortization of corporate-owned life insurance	7.5	7.0
Stock compensation	3.9	4.8
Net deferred income taxes and credits	(11.0)	2.7
Allowance for equity funds used during construction	(3.2)	(2.7)
Payments for asset retirement obligations	(4.4)	(2.6)
Equity in earnings of equity method investees, net of income taxes	(1.8)	(1.9)
Income from corporate-owned life insurance	(7.5)	(8.6)
Other	0.3	0.3
Changes in working capital items:		
Accounts receivable	66.2	93.5
Accounts receivable pledged as collateral	(20.0)	(6.0)
Fuel inventory and supplies	(24.4)	(51.0)
Prepaid expenses and other current assets	(20.2)	0.3
Accounts payable	(152.9)	(197.8)
Accrued taxes	119.3	107.8
Other current liabilities	(37.1)	(3.2)
Changes in other assets	(10.4)	0.4
Changes in other liabilities	(9.2)	(8.9)
Cash Flows from Operating Activities	317.3	362.9
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:		
Additions to property, plant and equipment	(618.6)	(527.7)
Purchase of securities - trusts	(19.5)	(11.0)
Sale of securities - trusts	14.8	7.6
Investment in corporate-owned life insurance	(4.1)	(3.8)
Proceeds from investment in corporate-owned life insurance	41.5	42.1
Other investing activities	2.7	(4.1)
Cash Flows used in Investing Activities	(583.2)	(496.9)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:		
Short-term debt, net	139.7	214.2
Collateralized short-term borrowings, net	20.0	6.0
Proceeds from long-term debt	326.1	393.7
Retirements of long-term debt	—	(300.0)
Borrowings against cash surrender value of corporate-owned life insurance	0.6	0.6
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(29.4)	(32.5)
Cash dividends paid	(147.7)	(140.7)
Other financing activities	(5.7)	(4.1)
Cash Flows from Financing Activities	303.6	137.2
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	37.7	3.2
CASH, CASH EQUIVALENTS AND RESTRICTED CASH:		
Beginning of period	27.7	25.2
End of period	$ 65.4	$ 28.4

The accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
Consolidated Statements of Changes in Equity
(Unaudited)

	Evergy, Inc. Shareholders					
	Common stock shares	**Common stock**	**Retained earnings**	**AOCI**	**Non-controlling interests**	**Total equity**
	(millions, except share amounts)					
Balance as of December 31, 2022	229,546,105	$ 7,219.7	$ 2,298.5	$ (34.5)	$ 9.6	$ 9,493.3
Net income	—	—	142.6	—	3.1	145.7
Issuance of stock compensation and reinvested dividends, net of tax withholding	130,594	(2.4)	—	—	—	(2.4)
Dividends declared on common stock ($0.6125 per share)	—	—	(140.7)	—	—	(140.7)
Dividend equivalents declared	—	—	(0.4)	—	—	(0.4)
Stock compensation expense	—	4.7	—	—	—	4.7
Unearned compensation						
Compensation expense recognized	—	0.1	—	—	—	0.1
Derivative hedging activity, net of tax	—	—	—	1.3	—	1.3
Other	—	0.1	—	—	—	0.1
Balance as of March 31, 2023	229,676,699	$ 7,222.2	$ 2,300.0	$ (33.2)	$ 12.7	$ 9,501.7
Balance as of December 31, 2023	229,729,296	$ 7,234.9	$ 2,457.8	$ (29.6)	$ 21.9	$ 9,685.0
Net income	—	—	122.7	—	3.1	125.8
Issuance of stock compensation and reinvested dividends, net of tax withholding	193,042	(4.0)	—	—	—	(4.0)
Dividends declared on common stock ($0.6425 per share)	—	—	(147.7)	—	—	(147.7)
Dividend equivalents declared	—	—	(0.4)	—	—	(0.4)
Stock compensation expense	—	3.9	—	—	—	3.9
Derivative hedging activity, net of tax	—	—	—	1.3	—	1.3
Other	—	0.2	—	—	—	0.2
Balance as of March 31, 2024	229,922,338	$ 7,235.0	$ 2,432.4	$ (28.3)	$ 25.0	$ 9,664.1

The accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Balance Sheets
(Unaudited)

	March 31 2024	December 31 2023
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	**$ 32.5**	$ 9.2
Receivables, net of allowance for credit losses of $9.0 and $11.6, respectively	**125.6**	171.8
Related party receivables	**10.9**	11.6
Accounts receivable pledged as collateral	**182.0**	166.0
Fuel inventory and supplies	**422.4**	411.9
Income taxes receivable	**3.9**	11.5
Regulatory assets	**134.1**	127.7
Prepaid expenses	**29.2**	22.9
Other assets	**9.5**	13.2
Total Current Assets	**950.1**	945.8
PROPERTY, PLANT AND EQUIPMENT, NET, includes $131.8 and $133.6 related to variable interest entity, respectively	**12,244.9**	12,121.9
OTHER ASSETS:		
Regulatory assets	**490.0**	505.2
Nuclear decommissioning trust fund	**375.9**	365.1
Other	**304.3**	288.6
Total Other Assets	**1,170.2**	1,158.9
TOTAL ASSETS	**$ 14,365.2**	$ 14,226.6

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Balance Sheets
(Unaudited)

	March 31 2024	December 31 2023
LIABILITIES AND EQUITY	(millions, except share amounts)	
CURRENT LIABILITIES:		
Commercial paper	**$ 261.5**	$ 230.4
Collateralized note payable	**182.0**	166.0
Accounts payable	**158.0**	244.7
Related party payables	**361.5**	294.4
Accrued taxes	**161.7**	111.1
Accrued interest	**96.3**	79.7
Regulatory liabilities	**80.6**	104.1
Asset retirement obligations	**24.0**	22.2
Accrued compensation and benefits	**29.9**	37.6
Other	**103.4**	142.4
Total Current Liabilities	**1,458.9**	1,432.6
LONG-TERM LIABILITIES:		
Long-term debt, net	**4,581.0**	4,580.4
Deferred income taxes	**850.6**	844.2
Unamortized investment tax credits	**55.3**	56.2
Regulatory liabilities	**1,414.3**	1,432.4
Pension and post-retirement liability	**261.1**	256.3
Asset retirement obligations	**581.1**	577.1
Other	**159.4**	155.5
Total Long-Term Liabilities	**7,902.8**	7,902.1
Commitments and Contingencies (Note 10)		
EQUITY:		
Evergy Kansas Central, Inc. Shareholder's Equity:		
Common stock - 1,000 shares authorized, $0.01 par value, 1 share issued	**2,737.6**	2,737.6
Retained earnings	**2,240.9**	2,132.4
Total Evergy Kansas Central, Inc. Shareholder's Equity	**4,978.5**	4,870.0
Noncontrolling Interests	**25.0**	21.9
Total Equity	**5,003.5**	4,891.9
TOTAL LIABILITIES AND EQUITY	**$ 14,365.2**	$ 14,226.6

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Statements of Income
(Unaudited)

Three Months Ended March 31	2024	2023
	(millions)	
OPERATING REVENUES	$ 693.2	$ 678.6
OPERATING EXPENSES:		
Fuel and purchased power	138.6	144.4
SPP network transmission costs	72.7	81.2
Operating and maintenance	116.3	107.6
Depreciation and amortization	139.1	124.1
Taxes other than income tax	63.2	55.7
Total Operating Expenses	529.9	513.0
INCOME FROM OPERATIONS	163.3	165.6
OTHER INCOME (EXPENSE):		
Investment earnings	0.9	1.3
Other income	8.2	9.2
Other expense	(3.7)	(9.9)
Total Other Income, Net	5.4	0.6
Interest expense	55.8	52.4
INCOME BEFORE INCOME TAXES	112.9	113.8
Income tax expense	2.1	8.4
Equity in earnings of equity method investees, net of income taxes	0.8	1.0
NET INCOME	111.6	106.4
Less: Net income attributable to noncontrolling interests	3.1	3.1
NET INCOME ATTRIBUTABLE TO EVERGY KANSAS CENTRAL, INC.	$ 108.5	$ 103.3

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Statements of Cash Flows
(Unaudited)

Three Months Ended March 31	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:	(millions)	
Net income	$ 111.6	$ 106.4
Adjustments to reconcile income to net cash from operating activities:		
Depreciation and amortization	139.1	124.1
Amortization of nuclear fuel	7.8	7.5
Amortization of deferred refueling outage	2.3	2.3
Amortization of corporate-owned life insurance	7.5	7.0
Net deferred income taxes and credits	(5.3)	(11.6)
Allowance for equity funds used during construction	(3.2)	(0.5)
Payments for asset retirement obligations	(2.4)	(2.0)
Equity in earnings of equity method investees, net of income taxes	(0.8)	(1.0)
Income from corporate-owned life insurance	(7.5)	(8.6)
Other	(1.4)	(1.4)
Changes in working capital items:		
Accounts receivable	32.8	83.0
Accounts receivable pledged as collateral	(16.0)	—
Fuel inventory and supplies	(10.4)	(20.1)
Prepaid expenses and other current assets	1.6	(2.1)
Accounts payable	(20.0)	(42.1)
Accrued taxes	58.2	71.1
Other current liabilities	(49.0)	0.2
Changes in other assets	(9.9)	0.3
Changes in other liabilities	(3.4)	5.0
Cash Flows from Operating Activities	231.6	317.5
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:		
Additions to property, plant and equipment	(320.8)	(267.2)
Purchase of securities - trusts	(3.2)	(2.9)
Sale of securities - trusts	1.6	1.9
Investment in corporate-owned life insurance	(4.1)	(3.8)
Proceeds from investment in corporate-owned life insurance	41.5	42.1
Other investing activities	1.3	1.0
Cash Flows used in Investing Activities	(283.7)	(228.9)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:		
Short-term debt, net	31.1	(449.1)
Collateralized short-term debt, net	16.0	—
Proceeds from long-term debt	—	393.7
Net money pool borrowings	57.8	—
Borrowings against cash surrender value of corporate-owned life insurance	0.6	0.6
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(29.4)	(32.5)
Other financing activities	(0.7)	(0.6)
Cash Flows from (used in) Financing Activities	75.4	(87.9)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	23.3	0.7
CASH, CASH EQUIVALENTS AND RESTRICTED CASH:		
Beginning of period	9.2	8.7
End of period	$ 32.5	$ 9.4

The disclosures regarding Evergy Kansas Central included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY KANSAS CENTRAL, INC.
Consolidated Statements of Changes in Equity
(Unaudited)

	Evergy Kansas Central, Inc. Shareholder				
	Common stock shares	**Common stock**	**Retained earnings**	**Non-controlling interests**	**Total equity**
	(millions, except share amounts)				
Balance as of December 31, 2022	1	$ 2,737.6	$ 1,760.2	$ 9.6	$ 4,507.4
Net income	—	—	103.3	3.1	106.4
Balance as of March 31, 2023	1	$ 2,737.6	$ 1,863.5	$ 12.7	$ 4,613.8
Balance as of December 31, 2023	1	$ 2,737.6	$ 2,132.4	$ 21.9	$ 4,891.9
Net income	—	—	108.5	3.1	111.6
Balance as of March 31, 2024	1	$ 2,737.6	$ 2,240.9	$ 25.0	$ 5,003.5

The disclosures regarding Evergy Kansas Central included in the accompanying Unaudited Notes to Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Balance Sheets
(Unaudited)

	March 31 2024	December 31 2023
ASSETS	(millions, except share amounts)	
CURRENT ASSETS:		
Cash and cash equivalents	**$ 11.0**	$ 3.3
Receivables, net of allowance for credit losses of $6.4 and $7.9, respectively	**26.6**	55.0
Related party receivables	**129.7**	128.5
Accounts receivable pledged as collateral	**130.0**	126.0
Fuel inventory and supplies	**276.0**	264.6
Regulatory assets	**63.5**	53.2
Prepaid expenses	**24.6**	20.9
Other assets	**18.9**	14.7
Total Current Assets	**680.3**	666.2
PROPERTY, PLANT AND EQUIPMENT, NET	**8,168.5**	8,131.2
OTHER ASSETS:		
Regulatory assets	**388.1**	380.8
Nuclear decommissioning trust fund	**430.0**	401.3
Other	**77.1**	77.0
Total Other Assets	**895.2**	859.1
TOTAL ASSETS	**$ 9,744.0**	$ 9,656.5

The disclosures regarding Evergy Metro included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Balance Sheets
(Unaudited)

	March 31 2024	December 31 2023
LIABILITIES AND EQUITY	(millions, except share amounts)	
CURRENT LIABILITIES:		
Commercial paper	**$ 220.2**	$ 423.3
Collateralized note payable	**130.0**	126.0
Accounts payable	**162.2**	272.5
Related party payables	**0.2**	1.1
Accrued taxes	**87.0**	45.7
Accrued interest	**44.4**	27.4
Regulatory liabilities	**35.4**	43.0
Asset retirement obligations	**16.3**	16.0
Accrued compensation and benefits	**26.8**	36.9
Other	**54.4**	58.3
Total Current Liabilities	**776.9**	1,050.2
LONG-TERM LIABILITIES:		
Long-term debt, net	**3,217.6**	2,924.4
Deferred income taxes	**810.0**	797.2
Unamortized investment tax credits	**110.5**	111.3
Regulatory liabilities	**872.6**	860.2
Pension and post-retirement liability	**197.1**	190.8
Asset retirement obligations	**447.0**	444.4
Other	**86.7**	85.0
Total Long-Term Liabilities	**5,741.5**	5,413.3
Commitments and Contingencies (Note 10)		
EQUITY:		
Common stock - 1,000 shares authorized, without par value, 1 share issued, stated value	**1,563.1**	1,563.1
Retained earnings	**1,658.9**	1,626.2
Accumulated other comprehensive income	**3.6**	3.7
Total Equity	**3,225.6**	3,193.0
TOTAL LIABILITIES AND EQUITY	**$ 9,744.0**	$ 9,656.5

The disclosures regarding Evergy Metro included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Statements of Comprehensive Income
(Unaudited)

Three Months Ended March 31	2024	2023
	(millions)	
OPERATING REVENUES	$ 420.9	$ 406.4
OPERATING EXPENSES:		
Fuel and purchased power	136.6	115.4
Operating and maintenance	67.9	65.3
Depreciation and amortization	100.5	102.4
Taxes other than income tax	37.3	33.5
Total Operating Expenses	342.3	316.6
INCOME FROM OPERATIONS	78.6	89.8
OTHER INCOME (EXPENSE):		
Investment earnings	1.6	0.7
Other income	0.1	2.8
Other expense	(3.6)	(9.0)
Total Other Expense, Net	(1.9)	(5.5)
Interest expense	37.6	30.6
INCOME BEFORE INCOME TAXES	39.1	53.7
Income tax expense	6.4	6.9
NET INCOME	$ 32.7	$ 46.8
COMPREHENSIVE INCOME		
NET INCOME	$ 32.7	$ 46.8
OTHER COMPREHENSIVE INCOME:		
Derivative hedging activity		
Reclassification to expenses, net of tax	(0.1)	(0.1)
Derivative hedging activity, net of tax	(0.1)	(0.1)
Total other comprehensive loss	(0.1)	(0.1)
COMPREHENSIVE INCOME	$ 32.6	$ 46.7

The disclosures regarding Evergy Metro included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC.
Consolidated Statements of Cash Flows
(Unaudited)

Three Months Ended March 31	2024	2023
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:	(millions)	
Net income	$ 32.7	$ 46.8
Adjustments to reconcile income to net cash from operating activities:		
Depreciation and amortization	100.5	102.4
Amortization of nuclear fuel	7.9	7.6
Amortization of deferred refueling outage	2.3	2.3
Net deferred income taxes and credits	1.1	10.4
Allowance for equity funds used during construction	—	(2.3)
Payments for asset retirement obligations	(2.0)	(0.5)
Other	(0.1)	(0.1)
Changes in working capital items:		
Accounts receivable	29.8	22.8
Accounts receivable pledged as collateral	(4.0)	(6.0)
Fuel inventory and supplies	(11.4)	(17.5)
Prepaid expenses and other current assets	(24.8)	(25.4)
Accounts payable	(76.0)	(78.3)
Accrued taxes	41.3	30.1
Other current liabilities	2.3	0.7
Changes in other assets	(1.7)	7.8
Changes in other liabilities	4.2	(7.1)
Cash Flows from Operating Activities	102.1	93.7
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:		
Additions to property, plant and equipment	(187.2)	(189.0)
Purchase of securities - trusts	(16.3)	(8.2)
Sale of securities - trusts	13.2	5.7
Net money pool lending	—	31.0
Other investing activities	2.3	1.6
Cash Flows used in Investing Activities	(188.0)	(158.9)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:		
Short-term debt, net	89.7	360.0
Collateralized short-term debt, net	4.0	6.0
Retirements of long-term debt	—	(300.0)
Other financing activities	(0.1)	(0.1)
Cash Flows from Financing Activities	93.6	65.9
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	7.7	0.7
CASH, CASH EQUIVALENTS AND RESTRICTED CASH:		
Beginning of period	3.3	3.1
End of period	$ 11.0	$ 3.8

The disclosures regarding Evergy Metro included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY METRO, INC
Consolidated Statements of Changes in Equity
(Unaudited)

	Common stock shares	Common Stock	Retained earnings	AOCI - Net gains (losses) on cash flow hedges	Total equity
	(millions, except share amounts)				
Balance as of December 31, 2022	1	$ 1,563.1	$ 1,619.2	$ 4.0	$ 3,186.3
Net income	—	—	46.8	—	46.8
Derivative hedging activity, net of tax	—	—	—	(0.1)	(0.1)
Balance as of March 31, 2023	1	$ 1,563.1	$ 1,666.0	$ 3.9	$ 3,233.0
Balance as of December 31, 2023	1	$ 1,563.1	$ 1,626.2	$ 3.7	$ 3,193.0
Net income	—	—	32.7	—	32.7
Derivative hedging activity, net of tax	—	—	—	(0.1)	(0.1)
Balance as of March 31, 2024	1	$ 1,563.1	$ 1,658.9	$ 3.6	$ 3,225.6

The disclosures regarding Evergy Metro included in the accompanying Notes to Unaudited Consolidated Financial Statements are an integral part of these statements.

EVERGY, INC.
EVERGY KANSAS CENTRAL, INC.
EVERGY METRO, INC.

Combined Notes to Unaudited Consolidated Financial Statements

The notes to unaudited consolidated financial statements that follow are a combined presentation for Evergy, Inc., Evergy Kansas Central, Inc. and Evergy Metro, Inc., all registrants under this filing. The terms "Evergy," "Evergy Kansas Central," "Evergy Metro" and "Evergy Companies" are used throughout this report. "Evergy" refers to Evergy, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Kansas Central" refers to Evergy Kansas Central, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Metro" refers to Evergy Metro, Inc. and its consolidated subsidiaries, unless otherwise indicated. "Evergy Companies" refers to Evergy, Evergy Kansas Central and Evergy Metro, collectively, which are individual registrants within the Evergy consolidated group.

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Evergy is a public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy operates primarily through the following wholly-owned direct subsidiaries listed below.

- Evergy Kansas Central, Inc. (Evergy Kansas Central) is an integrated, regulated electric utility that provides electricity to customers in the state of Kansas. Evergy Kansas Central has one active wholly-owned subsidiary with significant operations, Evergy Kansas South, Inc. (Evergy Kansas South).
- Evergy Metro, Inc. (Evergy Metro) is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
- Evergy Missouri West, Inc. (Evergy Missouri West) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.
- Evergy Transmission Company, LLC (Evergy Transmission Company) owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC, a subsidiary of American Electric Power Company, Inc. (AEP). Transource is focused on the development of competitive electric transmission projects. Evergy Transmission Company accounts for its investment in Transource under the equity method.

Evergy Kansas Central also owns a 50% interest in Prairie Wind Transmission, LLC (Prairie Wind), which is a joint venture between Evergy Kansas Central and subsidiaries of AEP and Berkshire Hathaway Energy Company. Prairie Wind owns a 108-mile, 345 kilovolt (kV) double-circuit transmission line that provides transmission service in the Southwest Power Pool, Inc. (SPP). Evergy Kansas Central accounts for its investment in Prairie Wind under the equity method.

Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West conduct business in their respective service territories using the name Evergy. Collectively, the Evergy Companies have approximately 15,800 megawatts (MWs) of owned generating capacity and renewable power purchase agreements and engage in the generation, transmission, distribution and sale of electricity to approximately 1.7 million customers in the states of Kansas and Missouri.

Basis of Presentation

These unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) for interim financial information and with the instructions to Form 10-Q and Regulation S-X. Accordingly, these unaudited consolidated financial statements do not include all of the information and notes required by GAAP for annual financial statements and should be read in conjunction with the consolidated financial statements in the Evergy Companies' combined 2023 Form 10-K.

These unaudited consolidated financial statements, in the opinion of management, reflect all normal recurring adjustments necessary to fairly present the unaudited consolidated financial statements for each of the Evergy Companies for these interim periods. In preparing financial statements that conform to GAAP, management must make estimates and assumptions that affect the reported amounts of assets and liabilities, the reported amounts of revenues and expenses, and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Principles of Consolidation

Each of Evergy's, Evergy Kansas Central's and Evergy Metro's unaudited consolidated financial statements includes the accounts of their subsidiaries and the variable interest entities (VIE) of which Evergy and Evergy Kansas Central are the primary beneficiaries. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany transactions have been eliminated. The Evergy Companies assess financial performance and allocate resources on a consolidated basis (i.e., operate in one segment).

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consists of highly liquid investments with original maturities of three months or less at acquisition. Evergy has restricted cash included in Other within Other Assets on Evergy's consolidated balance sheets to facilitate servicing of Evergy Missouri West Storm Funding I, LLC's (Evergy Missouri West Storm Funding) debt. See Note 12 for additional information on the VIE. The following table summarizes the cash, cash equivalents and restricted cash included on Evergy's consolidated balance sheets.

	March 31 2024	December 31 2023
Evergy	(millions)	
Current assets		
Cash and cash equivalents	$ 63.7	$ 27.7
Other assets		
Other	1.7	—
Total cash, cash equivalents and restricted cash	$ 65.4	$ 27.7

Fuel Inventory and Supplies

The Evergy Companies record fuel inventory and supplies at average cost. The following table separately states the balances for fuel inventory and supplies.

	March 31 2024	December 31 2023
Evergy	(millions)	
Fuel inventory	$ 263.8	$ 257.3
Supplies	536.9	518.9
Fuel inventory and supplies	$ 800.7	$ 776.2
Evergy Kansas Central		
Fuel inventory	$ 142.1	$ 138.6
Supplies	280.3	273.3
Fuel inventory and supplies	$ 422.4	$ 411.9
Evergy Metro		
Fuel inventory	$ 84.2	$ 81.5
Supplies	191.8	183.1
Fuel inventory and supplies	$ 276.0	$ 264.6

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Property, Plant and Equipment

The following tables summarize the property, plant and equipment of Evergy, Evergy Kansas Central and Evergy Metro.

March 31, 2024	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
Electric plant in service	$ 34,923.8	$ 17,049.7	$ 13,098.8
Electric plant acquisition adjustment	724.9	724.9	—
Accumulated depreciation	(13,493.2)	(6,581.6)	(5,494.3)
Plant in service, net	22,155.5	11,193.0	7,604.5
Construction work in progress	1,598.9	956.2	468.4
Nuclear fuel, net	190.5	94.9	95.6
Plant to be retired, net[b]	0.8	0.8	—
Property, plant and equipment, net	$ 23,945.7	$ 12,244.9	$ 8,168.5

December 31, 2023	Evergy	Evergy Kansas Central	Evergy Metro
		(millions)	
Electric plant in service[a]	$ 34,558.1	$ 16,858.7	$ 13,005.5
Electric plant acquisition adjustment	724.9	724.9	—
Accumulated depreciation[a]	(13,301.6)	(6,502.7)	(5,404.9)
Plant in service, net[a]	21,981.4	11,080.9	7,600.6
Construction work in progress	1,543.5	939.1	428.7
Nuclear fuel, net	203.0	101.1	101.9
Plant to be retired, net[b]	0.8	0.8	—
Property, plant and equipment, net[a]	$ 23,728.7	$ 12,121.9	$ 8,131.2

[a] As of March 31, 2024, Evergy and Evergy Kansas Central classified Property, Plant and Equipment of VIE, net as Property, Plant and Equipment, net. To conform with the current period presentation, amounts previously reported as Property, Plant and Equipment of VIE, net as of December 31, 2023, have been reclassified to Property, Plant and Equipment, net.

[b] As of March 31, 2024 and December 31, 2023, represents the planned retirement of Evergy Kansas Central analog meters prior to the end of their remaining useful lives.

Other Income (Expense), Net

The table below shows the detail of other expense for each of the Evergy Companies.

Three Months Ended March 31	2024	2023
Evergy	(millions)	
Non-service cost component of net benefit cost	$ (4.6)	$ (14.8)
Other	(4.9)	(6.5)
Other expense	$ (9.5)	$ (21.3)
Evergy Kansas Central		
Non-service cost component of net benefit cost	$ 0.5	$ (4.0)
Other	(4.2)	(5.9)
Other expense	$ (3.7)	$ (9.9)
Evergy Metro		
Non-service cost component of net benefit cost	$ (3.0)	$ (8.7)
Other	(0.6)	(0.3)
Other expense	$ (3.6)	$ (9.0)

Earnings Per Share

To compute basic earnings per common share (EPS), Evergy divides net income attributable to Evergy, Inc. by the weighted average number of common shares outstanding. Diluted EPS includes the effect of issuable common shares resulting from restricted share units (RSUs), restricted stock, convertible notes and a warrant. Evergy computes the dilutive effects of potential issuances of common shares using the treasury stock method, the contingently issuable share method or the if-converted method, as applicable.

The following table reconciles Evergy's basic and diluted EPS.

Three Months Ended March 31	2024	2023
Income	(millions, except per share amounts)	
Net income	$ 125.8	$ 145.7
Less: net income attributable to noncontrolling interests	3.1	3.1
Net income attributable to Evergy, Inc.	$ 122.7	$ 142.6
Common Shares Outstanding		
Weighted average number of common shares outstanding - basic	230.2	230.0
Add: effect of dilutive securities	0.2	0.3
Diluted average number of common shares outstanding	230.4	230.3
Basic and Diluted EPS	$ 0.53	$ 0.62

Anti-dilutive securities excluded from the computation of diluted EPS for the three months ended March 31, 2024 and 2023 were 3,950,000 common shares issuable pursuant to a warrant. Also, there was no dilution resulting from Evergy's convertible notes for the three months ended March 31, 2024 and 2023.

Dividends Declared

In May 2024, Evergy's Board of Directors (Evergy Board) declared a quarterly dividend of $0.6425 per share on Evergy's common stock. The common dividend is payable on June 20, 2024, to shareholders of record as of May 20, 2024.

Supplemental Cash Flow Information

Evergy

Three Months Ended March 31	2024	2023
Cash paid for (received from):	(millions)	
Interest, net of amount capitalized	$ 105.3	$ 133.0
Income taxes, net of refunds	(0.2)	(0.5)
Right-of-use assets obtained in exchange for new operating lease liabilities	1.9	6.2
Right-of-use assets obtained in exchange for new finance lease liabilities	5.1	—
Non-cash investing transactions:		
Property, plant and equipment additions	105.1	112.1

Evergy Kansas Central

Three Months Ended March 31	2024	2023
Cash paid for (received from):	(millions)	
Interest, net of amount capitalized	$ 48.8	$ 56.3
Income taxes, net of refunds	(0.2)	(0.2)
Right-of-use assets obtained in exchange for new operating lease liabilities	0.7	2.7
Right-of-use assets obtained in exchange for new finance lease liabilities	1.3	—
Non-cash investing transactions:		
Property, plant and equipment additions	47.6	54.8

Evergy Metro		
Three Months Ended March 31	**2024**	**2023**
Cash paid for (received from):	(millions)	
Interest, net of amount capitalized	$ 21.3	$ 31.1
Right-of-use assets obtained in exchange for new operating lease liabilities	1.0	3.5
Right-of-use assets obtained in exchange for new finance lease liabilities	3.5	—
Non-cash investing transactions:		
Property, plant and equipment additions	39.9	41.0

Natural Gas Plant Investment

In April 2024, Evergy Missouri West purchased a joint ownership interest representing approximately 145 MW in Dogwood Energy Center (Dogwood), an operational natural gas combined cycle facility located in Missouri, for approximately $60 million. The purchase was subject to terms and conditions listed in a stipulation and agreement approved by the Public Service Commission of the State of Missouri (MPSC) allowing Evergy Missouri West to recover in rates a return of and return on the original cost, net of accumulated depreciation, of Dogwood. Evergy Missouri West shall also be allowed to recover in rates over two years a return of, but not a return on, the amount of the purchase price paid in excess of the original cost, net of accumulated depreciation, of Dogwood. In addition, net revenues generated from Evergy Missouri West's ownership of Dogwood from the date of closing to the date new rates become effective in Evergy Missouri West's current rate case shall not impact rates and shall be retained by Evergy Missouri West and reduce the amount of the purchase price paid in excess of the original cost, net of accumulated depreciation, of Dogwood to be recovered from customers.

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2. REVENUE

Evergy's, Evergy Kansas Central's and Evergy Metro's revenues disaggregated by customer class are summarized in the following tables.

Evergy

Three Months Ended March 31	2024	2023
Revenues	(millions)	
Residential	$ 479.0	$ 458.6
Commercial	432.7	430.0
Industrial	160.4	159.1
Other retail	11.9	11.3
Total electric retail	$ 1,084.0	$ 1,059.0
Wholesale	71.0	70.4
Transmission	115.4	105.8
Industrial steam and other	10.2	11.7
Total revenue from contracts with customers	$ 1,280.6	$ 1,246.9
Other	50.4	49.9
Operating revenues	$ 1,331.0	$ 1,296.8

Evergy Kansas Central

Three Months Ended March 31	2024	2023
Revenues	(millions)	
Residential	$ 214.3	$ 192.1
Commercial	183.6	178.1
Industrial	106.0	108.5
Other retail	6.1	4.3
Total electric retail	$ 510.0	$ 483.0
Wholesale	68.1	67.6
Transmission	108.9	100.6
Other	1.8	1.7
Total revenue from contracts with customers	$ 688.8	$ 652.9
Other	4.4	25.7
Operating revenues	$ 693.2	$ 678.6

Evergy Metro		
Three Months Ended March 31	**2024**	**2023**
Revenues	(millions)	
Residential	$ 156.0	$ 158.0
Commercial	171.2	175.9
Industrial	31.2	28.4
Other retail	3.2	2.7
Total electric retail	$ 361.6	$ 365.0
Wholesale	6.3	11.4
Transmission	4.9	3.8
Other	2.5	2.4
Total revenue from contracts with customers	$ 375.3	$ 382.6
Other	45.6	23.8
Operating revenues	$ 420.9	$ 406.4

3. RECEIVABLES

The Evergy Companies' receivables are detailed in the following table.

	March 31 2024	December 31 2023
Evergy	(millions)	
Customer accounts receivable - billed	$ —	$ 2.6
Customer accounts receivable - unbilled	70.0	109.1
Other receivables	123.8	169.4
Allowance for credit losses	(18.5)	(24.2)
Total	$ 175.3	$ 256.9
Evergy Kansas Central		
Customer accounts receivable - unbilled	24.8	39.9
Other receivables	109.8	143.5
Allowance for credit losses	(9.0)	(11.6)
Total	$ 125.6	$ 171.8
Evergy Metro		
Customer accounts receivable - unbilled	9.9	27.2
Other receivables	23.1	35.7
Allowance for credit losses	(6.4)	(7.9)
Total	$ 26.6	$ 55.0

The Evergy Companies' other receivables as of March 31, 2024 and December 31, 2023, consisted primarily of receivables from partners in jointly-owned electric utility plants, wholesale sales receivables and receivables related to alternative revenue programs. The Evergy Companies' other receivables also included receivables from contracts with customers as summarized in the following table.

	March 31 2024	December 31 2023
	(millions)	
Evergy	$ 46.8	$ 61.5
Evergy Kansas Central	41.8	59.9
Evergy Metro	3.4	0.8

The change in the Evergy Companies' allowance for credit losses is summarized in the following table.

	2024	2023
Evergy	(millions)	
Beginning balance January 1	$ 24.2	$ 31.4
Credit loss expense (income)	(1.1)	(3.3)
Write-offs	(7.9)	(8.3)
Recoveries of prior write-offs	3.3	3.1
Ending balance March 31	$ 18.5	$ 22.9
Evergy Kansas Central		
Beginning balance January 1	$ 11.6	$ 16.9
Credit loss expense (income)	(0.4)	(1.8)
Write-offs	(3.6)	(4.3)
Recoveries of prior write-offs	1.4	1.3
Ending balance March 31	$ 9.0	$ 12.1
Evergy Metro		
Beginning balance January 1	$ 7.9	$ 9.3
Credit loss expense (income)	—	(0.8)
Write-offs	(2.8)	(2.7)
Recoveries of prior write-offs	1.3	1.2
Ending balance March 31	$ 6.4	$ 7.0

Sale of Accounts Receivable

Evergy Kansas Central, Evergy Metro and Evergy Missouri West sell an undivided percentage ownership interest in their retail electric accounts receivable to independent outside investors. These sales are accounted for as secured borrowings with accounts receivable pledged as collateral and a corresponding short-term collateralized note payable recognized on the balance sheets. The Evergy Companies' accounts receivable pledged as collateral and the corresponding short-term collateralized note payable are summarized in the following table.

	March 31 2024	December 31 2023
	(millions)	
Evergy	$ 362.0	$ 342.0
Evergy Kansas Central	182.0	166.0
Evergy Metro	130.0	126.0

In February 2024, Evergy Kansas Central, Evergy Metro and Evergy Missouri West amended the terms of their receivable sale facilities, including extending the expiration of each receivable sale facility from 2024 to 2025.

Prior to the amendment to Evergy Kansas Central's facility, it allowed for $185.0 million in aggregate outstanding principal amount of borrowings from mid-November through mid-July and then $200.0 million from mid-July through mid-November. Prior to the amendment to Evergy Metro's facility, it allowed for $130.0 million in aggregate outstanding principal amount of borrowings at any time. Prior to the amendment to Evergy Missouri West's facility, it allowed for $50.0 million in aggregate outstanding principal amount of borrowings from mid-November through mid-July and then $65.0 million from mid-July through mid-November.

Under the amended terms, effective in March 2024, Evergy Kansas Central's facility allows up to $185.0 million in aggregate outstanding principal amount to be borrowed at any time. To the extent Evergy Kansas Central has qualifying accounts receivable and subject to the bank's discretion, Evergy Kansas Central's facility allows for an additional $65.0 million in aggregate outstanding principal amount to be borrowed at any time. Evergy Metro's facility allows up to $130.0 million in aggregate outstanding principal amount to be borrowed at any time. To the extent Evergy Metro has qualifying accounts receivable and subject to the bank's discretion, Evergy Metro's facility allows for an additional $70.0 million in aggregate outstanding principal amount to be borrowed at any time. Evergy Missouri West's facility allows up to $50.0 million in aggregate outstanding principal amount to be borrowed at any time. To the extent Evergy Missouri West has qualifying accounts receivable and subject to the bank's discretion, Evergy Missouri West's facility allows for an additional $65.0 million in aggregate outstanding principal amount to be borrowed at any time.

4. RATE MATTERS AND REGULATION

State Corporation Commission of the State of Kansas (KCC) Proceedings

Evergy Kansas Central 2024 Transmission Delivery Charge (TDC)

In April 2024, the KCC issued an order adjusting Evergy Kansas Central's retail prices to include updated transmission costs as reflected in the Federal Energy Regulatory Commission (FERC) transmission formula rate (TFR). The new prices are effective in May 2024 and are expected to increase Evergy Kansas Central's annual retail revenues by $80.1 million when compared to 2023.

Evergy Metro 2024 TDC

In April 2024, the KCC issued an order adjusting Evergy Metro's retail prices to include updated transmission costs as reflected in the FERC TFR. The new prices are effective in May 2024 and are expected to increase Evergy Metro's annual retail revenues by $7.1 million when compared to 2023.

MPSC Proceedings

Evergy Missouri West's 2024 Rate Case Proceeding

In February 2024, Evergy Missouri West filed an application with the MPSC to request an increase to its retail revenues of approximately $104 million. Evergy Missouri West's request reflected a return on equity of 10.5% (with a capital structure composed of 52% equity) and increases related to the recovery of infrastructure investments made to improve reliability and enhance customer service and the inclusion of certain costs related to Dogwood and Crossroads Energy Center (Crossroads), two natural gas plants. An evidentiary hearing in the case is scheduled to occur beginning in late September 2024 and new rates are expected to be effective in January 2025.

Evergy Missouri West February 2021 Winter Weather Event Securitization

In February 2021, much of the central and southern United States, including the service territories of the Evergy Companies, experienced a significant winter weather event that resulted in extremely cold temperatures over a multi-day period (February 2021 winter weather event).

In November 2022, the MPSC issued a revised financing order authorizing Evergy Missouri West to issue securitized bonds to recover its extraordinary fuel and purchased power costs incurred as part of the February 2021 winter weather event. As part of the order, the MPSC found that Evergy Missouri West's costs were prudently incurred, that it should only be allowed to recover 95% of its extraordinary fuel and purchased power costs consistent with the 5% sharing provision of its fuel recovery mechanism, that it should be allowed to recover carrying costs incurred since February 2021 at Evergy Missouri West's long-term debt rate of 5.06% and approved a 15 year repayment period for the bonds with a 17 year legal maturity. Evergy Missouri West continued to record carrying charges on its February 2021 winter weather event regulatory asset until it issued the securitized bonds in February 2024. See Note 7 for additional information regarding the issuance of the securitized bonds.

FERC Proceedings
In October of each year, Evergy Kansas Central and Evergy Metro post an updated TFR that includes projected transmission capital expenditures and operating costs for the following year. This rate is the most significant component in the retail rate calculation for Evergy Kansas Central's and Evergy Metro's annual request with the KCC to adjust retail prices to include updated transmission costs through the TDC.

Evergy Kansas Central TFR Annual Update
In the most recent two years, the updated TFR was expected to adjust Evergy Kansas Central's annual transmission revenues by approximately:

- $115.8 million increase effective in January 2024; and
- $21.7 million decrease effective in March 2023.

See "Evergy Kansas Central TFR Formal Challenge" within this Note 4 for more information regarding the March 2023 adjustment.

Evergy Kansas Central TFR Formal Challenge
In March 2022, certain Evergy Kansas Central TFR customers submitted a formal challenge regarding the implementation of Evergy Kansas Central's TFR, specifically with regard to how Evergy Kansas Central's capital structure was calculated as part of determining the Annual Transmission Revenue Requirement (ATRR). As part of this challenge, the customers requested that Evergy Kansas Central make refunds for over-collections in rate years 2018 through 2022 as a result of the calculation of its capital structure included in the TFR. Evergy Kansas Central disputed that any refunds for 2018 through 2022 were required because Evergy Kansas Central was following its approved TFR formula.

In December 2022, FERC issued an order addressing the challenge to the 2020 through 2022 over-collections which were refunded to customers as part of Evergy Kansas Central's 2023 TFR effective in March 2023. In February 2023, certain Evergy Kansas Central TFR customers submitted a formal complaint with FERC requesting the refund of over-collections related to the 2018 and 2019 rate years. As of March 31, 2024 and December 31, 2023, Evergy and Evergy Kansas Central had recorded a $7.1 million regulatory liability related to the 2018 and 2019 rate year refund request. A decision from FERC regarding this complaint is expected in 2024.

Evergy Metro TFR Annual Update
In the most recent two years, the updated TFR was expected to adjust Evergy Metro's annual transmission revenues by approximately:

- $23.7 million increase effective in January 2024; and
- $8.6 million increase effective in January 2023.

5. PENSION PLANS AND POST-RETIREMENT BENEFITS

Evergy and certain of its subsidiaries maintain, and Evergy Kansas Central and Evergy Metro participate in, qualified non-contributory defined benefit pension plans covering the majority of Evergy Kansas Central's and Evergy Metro's employees as well as certain non-qualified plans covering certain active and retired officers. Evergy is also responsible for its indirect 94% ownership share of Wolf Creek Generating Station's (Wolf Creek) defined benefit plans, consisting of Evergy Kansas South's and Evergy Metro's respective 47% ownership shares.

For the majority of employees, pension benefits under these plans reflect the employees' compensation, years of service and age at retirement. However, for the plan covering Evergy Kansas Central's employees, the benefits for non-union employees hired between 2002 and the second quarter of 2018 and union employees hired beginning in 2012 are derived from a cash balance account formula. The plan was closed to future non-union employees in

2018. For the plans covering Evergy Metro's employees, the benefits for union employees hired beginning in 2014 are derived from a cash balance account formula and the plans were closed to future non-union employees in 2014.

Evergy and its subsidiaries also provide certain post-retirement health care and life insurance benefits for substantially all retired employees of Evergy Kansas Central and Evergy Metro and their respective shares of Wolf Creek's post-retirement benefit plans.

The Evergy Companies record pension and post-retirement expense in accordance with rate orders from the KCC and MPSC that allow the difference between pension and post-retirement costs under GAAP and costs for ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods is due to timing and will be eliminated over the life of the plans.

For the three months ended March 31, 2024, Evergy, Evergy Kansas Central and Evergy Metro recorded no pension settlement charges. For the three months ended March 31, 2023, Evergy, Evergy Kansas Central and Evergy Metro recorded pension settlement (gains) losses of $(15.9) million, $0.4 million and $(16.3) million, respectively. These settlement charges were the result of accelerated distributions as a result of employee retirements for certain plan participants. Evergy, Evergy Kansas Central and Evergy Metro deferred substantially all of the charges to regulatory assets or regulatory liabilities and expect to recover these amounts over future periods pursuant to regulatory agreements.

The following tables provide the components of net periodic benefit costs prior to the effects of capitalization and sharing with joint owners of power plants.

	Pension Benefits			Post-Retirement Benefits		
Three Months Ended March 31, 2024	**Evergy**	**Evergy Kansas Central**	**Evergy Metro**	**Evergy**	**Evergy Kansas Central**	**Evergy Metro**
Components of net periodic benefit costs			(millions)			
Service cost	$ 11.5	$ 4.7	$ 6.8	$ 0.4	$ 0.2	$ 0.2
Interest cost	22.4	11.4	10.7	2.5	1.3	1.2
Expected return on plan assets	(21.7)	(10.7)	(10.9)	(2.8)	(1.5)	(1.4)
Prior service cost	0.5	0.5	—	—	—	(0.1)
Recognized net actuarial (gain) loss	(4.3)	0.2	(4.4)	(1.0)	(0.5)	(0.4)
Net periodic benefit costs before regulatory adjustment and intercompany allocations	8.4	6.1	2.2	(0.9)	(0.5)	(0.5)
Regulatory adjustment	5.7	(2.1)	7.7	—	0.2	(0.1)
Intercompany allocations	—	(0.4)	(0.5)	—	—	0.1
Net periodic benefit costs (income)	$ 14.1	$ 3.6	$ 9.4	$ (0.9)	$ (0.3)	$ (0.5)

Three Months Ended March 31, 2023	Pension Benefits Evergy	Pension Benefits Evergy Kansas Central	Pension Benefits Evergy Metro	Post-Retirement Benefits Evergy	Post-Retirement Benefits Evergy Kansas Central	Post-Retirement Benefits Evergy Metro
Components of net periodic benefit costs			(millions)			
Service cost	$ 11.2	$ 4.6	$ 6.6	$ 0.4	$ 0.2	$ 0.2
Interest cost	22.4	11.4	10.8	2.8	1.4	1.3
Expected return on plan assets	(21.8)	(11.0)	(10.8)	(3.0)	(1.5)	(1.4)
Prior service cost	0.5	0.5	—	—	—	(0.1)
Recognized net actuarial gain	(5.6)	(0.8)	(4.6)	(1.0)	(0.5)	(0.5)
Settlement (gain) loss	(15.9)	0.4	(16.3)	—	—	—
Net periodic benefit costs before regulatory adjustment and intercompany allocations	(9.2)	5.1	(14.3)	(0.8)	(0.4)	(0.5)
Regulatory adjustment	33.5	7.4	25.9	(0.1)	(0.6)	0.6
Intercompany allocations	—	(0.5)	(0.2)	—	0.1	—
Net periodic benefit costs (income)	$ 24.3	$ 12.0	$ 11.4	$ (0.9)	$ (0.9)	$ 0.1

The components of net periodic benefit costs other than the service cost component are included in other expense on the Evergy Companies' consolidated statements of income and comprehensive income.

For the three months ended March 31, 2024, Evergy, Evergy Kansas Central and Evergy Metro made no cash pension contributions. Evergy expects to make cash pension contributions of $38.6 million in 2024 to satisfy the Employee Retirement Income Security Act of 1974, as amended (ERISA) funding requirements and KCC and MPSC rate orders, of which $11.7 million is expected to be paid by Evergy Kansas Central and $26.9 million is expected to be paid by Evergy Metro.

For the three months ended March 31, 2024, Evergy, Evergy Kansas Central and Evergy Metro made post-retirement benefit contributions of $0.4 million, $0.2 million and $0.2 million, respectively. Evergy, Evergy Kansas Central and Evergy Metro expect to make additional contributions in 2024 of $0.4 million, $0.2 million and $0.2 million, respectively, to the post-retirement benefit plans.

6. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

Evergy's $2.5 billion master credit facility expires in 2027. Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West have borrowing capacity under the master credit facility with specific sublimits for each borrower. These sublimits can be unilaterally adjusted by Evergy for each borrower provided the sublimits remain within minimum and maximum sublimits as specified in the facility. The applicable interest rates and commitment fees of the facility are subject to upward or downward adjustments, within certain limitations, if Evergy achieves, or fails to achieve, certain sustainability-linked targets based on two key performance indicator metrics: (i) Non-Emitting Generation Capacity and (ii) Diverse Supplier Spend (as defined in the facility).

A default by any borrower under the facility or one of its significant subsidiaries on other indebtedness totaling more than $100.0 million constitutes a default by that borrower under the facility. Under the terms of this facility, each of Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West is required to maintain a total indebtedness to total capitalization ratio, as defined in the facility, of not greater than 0.65 to 1.00 at all times. As of March 31, 2024, Evergy, Evergy Kansas Central, Evergy Metro and Evergy Missouri West were in compliance with this covenant.

The following table summarizes the committed credit facilities (excluding receivable sale facilities discussed in Note 3) available to the Evergy Companies as of March 31, 2024 and December 31, 2023.

	Master Credit Facility	Amounts Drawn: Commercial Paper	Amounts Drawn: Letters of Credit	Amounts Drawn: Cash Borrowings	Available Borrowings	Weighted Average Interest Rate on Short-Term Borrowings
March 31, 2024			(millions)			
Evergy, Inc.	$ 200.0	$ —	$ 0.7	$ —	$ 199.3	—%
Evergy Kansas Central	750.0	261.5	1.0	—	487.5	5.51%
Evergy Metro[a]	850.0	513.0	—	—	337.0	5.52%
Evergy Missouri West	700.0	317.0	—	—	383.0	5.51%
Evergy[a]	$ 2,500.0	$ 1,091.5	$ 1.7	$ —	$ 1,406.8	
December 31, 2023						
Evergy, Inc.	$ 300.0	$ —	$ 0.7	$ —	$ 299.3	—%
Evergy Kansas Central	750.0	230.4	1.0	—	518.6	5.56%
Evergy Metro	750.0	423.3	—	—	326.7	5.58%
Evergy Missouri West	700.0	298.1	—	—	401.9	5.66%
Evergy	$ 2,500.0	$ 951.8	$ 1.7	$ —	$ 1,546.5	

[a] As of March 31, 2024, $292.8 million of Evergy Metro's commercial paper borrowings were classified as long-term debt on Evergy's and Evergy Metro's consolidated balance sheets. See Note 7 for additional information.

7. LONG-TERM DEBT

Mortgage Bonds

In April 2024, Evergy Metro issued, at a discount, $300.0 million of 5.40% Mortgage Bonds, maturing in 2034. Proceeds were used to pay down commercial paper and for general corporate purposes. As of March 31, 2024, $292.8 million of Evergy Metro's commercial paper borrowings were classified as long-term debt on Evergy's and Evergy Metro's consolidated balance sheets as a result of Evergy and Evergy Metro demonstrating their intent and ability to refinance the commercial paper on a long-term basis.

Securitized Bonds

In 2022, Evergy Missouri West created a special purpose subsidiary, Evergy Missouri West Storm Funding, a wholly-owned, bankruptcy remote entity solely for the purpose of recovering extraordinary fuel and purchased power costs incurred as part of the February 2021 winter weather event. In February 2024, Evergy Missouri West Storm Funding issued, at a discount, $331.1 million of 5.10% Securitized Utility Tariff Bonds (Securitized Bonds) with a final payment scheduled for 2038, maturing in 2040. The obligations of Evergy Missouri West Storm Funding's Securitized Bonds are repaid through charges imposed on customers in Evergy Missouri West's service territory. Creditors of Evergy Missouri West have no recourse to any assets or revenues of Evergy Missouri West Storm Funding, and the bondholders have no recourse to the general credit of Evergy Missouri West. See Note 4 for additional information regarding the February 2021 winter weather event securitization.

8. DERIVATIVE INSTRUMENTS

The Evergy Companies engage in the wholesale and retail sale of electricity as part of their regulated electric operations, in addition to limited non-regulated energy marketing activities. These activities expose the Evergy Companies to market risks associated with the price of electricity, natural gas and other energy-related products. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on the Evergy Companies' operating results. The Evergy Companies' commodity risk management activities, which are subject to the management, direction and control of an internal risk management committee, utilize derivative instruments to reduce the effects of fluctuations in wholesale sales and fuel and purchased power expense caused by commodity price volatility.

The Evergy Companies are also exposed to market risks arising from changes in interest rates and may use derivative instruments to manage these risks. The Evergy Companies' interest rate risk management activities have included using derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances.

The Evergy Companies also engage in non-regulated energy marketing activity for trading purposes, primarily at Evergy Kansas Central, which focuses on seizing market opportunities to create value driven by expected changes in the market prices of commodities, primarily electricity and natural gas.

The Evergy Companies consider various qualitative factors, such as contract and marketplace attributes, in designating derivative instruments at inception. The Evergy Companies may elect the normal purchases and normal sales (NPNS) exception, which requires the effects of the derivative to be recorded when the underlying contract settles under accrual accounting. The Evergy Companies account for derivative instruments that are not designated as NPNS primarily as either economic hedges or trading contracts (non-hedging derivatives) which are recorded as assets or liabilities on the consolidated balance sheets at fair value. See Note 9 for additional information on the Evergy Companies' methods for assessing the fair value of derivative instruments. Changes in the fair value of non-hedging derivatives that are related to the Evergy Companies' regulated operations are deferred to a regulatory asset or regulatory liability when determined to be probable of future recovery or refund from customers. Recovery of the actual costs incurred by regulated activities will not impact earnings but will impact cash flows due to the timing of the recovery mechanism. Cash flows for all derivative instruments are classified as operating activities on the Evergy Companies' statements of cash flows, with the exception of cash flows for interest rate swap agreements accounted for as cash flows hedges of forecasted debt transactions, which are recorded as financing activities. Changes in the fair value of non-hedging derivatives that are not related to the Evergy Companies' regulated operations are recorded in operating revenues on the Evergy Companies' statements of income and comprehensive income.

The Evergy Companies offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable).

The gross notional contract amount by commodity type for derivative instruments is summarized in the following table.

Non-hedging derivatives	Notional volume unit of measure	March 31 2024	December 31 2023
Evergy		(millions)	
Commodity contracts			
Power	MWhs	28.3	52.9
Natural gas	MMBtu	550.1	559.9
Evergy Kansas Central			
Commodity contracts			
Power	MWhs	18.8	32.1
Natural gas	MMBtu	550.1	558.7
Evergy Metro			
Commodity contracts			
Power	MWhs	7.1	15.1

The fair values of Evergy's open derivative positions and balance sheet classifications are summarized in the following tables. The fair values below are gross values before netting agreements and netting of cash collateral.

Evergy		March 31 2024	December 31 2023
Non-hedging derivatives	**Balance sheet location**		
Commodity contracts		(millions)	
Power	Other assets - current	$ 15.3	$ 23.2
	Other assets - long-term	42.2	35.7
Natural gas	Other assets - current	26.7	68.1
	Other assets - long-term	5.6	6.0
Total derivative assets		$ 89.8	$ 133.0
Commodity contracts			
Power	Other liabilities - current	$ 9.0	$ 21.0
	Other liabilities - long-term	39.6	32.9
Natural gas	Other liabilities - current	27.5	68.1
	Other liabilities - long-term	6.4	6.8
Total derivative liabilities		$ 82.5	$ 128.8

Evergy Kansas Central		March 31 2024	December 31 2023
Non-hedging derivatives	**Balance sheet location**		
Commodity contracts		(millions)	
Power	Other assets - current	$ 10.5	$ 18.3
	Other assets - long-term	42.3	35.7
Natural gas	Other assets - current	26.7	68.1
	Other assets - long-term	5.6	6.0
Total derivative assets		$ 85.1	$ 128.1
Commodity contracts			
Power	Other liabilities - current	$ 7.8	$ 14.3
	Other liabilities - long-term	39.6	32.9
Natural gas	Other liabilities - current	27.5	67.0
	Other liabilities - long-term	6.4	6.8
Total derivative liabilities		$ 81.3	$ 121.0

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Evergy Metro		March 31 2024	December 31 2023
Non-hedging derivatives	**Balance sheet location**		
Commodity contracts		(millions)	
Power	Other assets - current	$ 2.6	$ 2.1
Total derivative assets		$ 2.6	$ 2.1
Commodity contracts			
Power	Other liabilities - current	$ 1.0	$ 5.7
Total derivative liabilities		$ 1.0	$ 5.7

The following tables present the line items on the Evergy Companies' consolidated balance sheets where derivative assets and liabilities are reported. The gross amounts offset in the tables below show the effect of master netting arrangements and include collateral posted to offset the net position.

March 31, 2024	Evergy	Evergy Kansas Central	Evergy Metro
Derivative Assets		(millions)	
Current			
Gross amounts recognized	$ 42.0	$ 37.2	$ 2.6
Gross amounts offset	(31.0)	(29.8)	(1.0)
Net amounts presented in other assets - current	$ 11.0	$ 7.4	$ 1.6
Long-Term			
Gross amounts recognized	$ 47.8	$ 47.9	$ —
Gross amounts offset	(11.2)	(11.2)	—
Net amounts presented in other assets - long-term	$ 36.6	$ 36.7	$ —
Derivative Liabilities			
Current			
Gross amounts recognized	$ 36.5	$ 35.3	$ 1.0
Gross amounts offset	(30.1)	(28.9)	(1.0)
Net amounts presented in other liabilities - current	$ 6.4	$ 6.4	$ —
Long-Term			
Gross amounts recognized	$ 46.0	$ 46.0	$ —
Gross amounts offset	(7.7)	(7.7)	—
Net amounts presented in other liabilities - long-term	$ 38.3	$ 38.3	$ —

December 31, 2023	Evergy	Evergy Kansas Central	Evergy Metro
Derivative Assets		(millions)	
Current			
Gross amounts recognized	$ 91.3	$ 86.4	$ 2.1
Gross amounts offset	(78.4)	(75.3)	(2.1)
Net amounts presented in other assets - current	$ 12.9	$ 11.1	$ —
Long-Term			
Gross amounts recognized	$ 41.7	$ 41.7	$ —
Gross amounts offset	(11.9)	(11.9)	—
Net amounts presented in other assets - long-term	$ 29.8	$ 29.8	$ —
Derivative Liabilities			
Current			
Gross amounts recognized	$ 89.1	$ 81.3	$ 5.7
Gross amounts offset	(77.5)	(74.4)	(2.1)
Net amounts presented in other liabilities - current	$ 11.6	$ 6.9	$ 3.6
Long-Term			
Gross amounts recognized	$ 39.7	$ 39.7	$ —
Gross amounts offset	(5.9)	(5.9)	—
Net amounts presented in other liabilities - long-term	$ 33.8	$ 33.8	$ —

The following table summarizes the amounts of gain (loss) recognized in income for the change in fair value of derivatives not designated as hedging instruments for the Evergy Companies.

Three Months Ended March 31		2024	2023
Location of gain (loss)	**Contract type**		
Evergy		(millions)	
Operating revenues	Commodity	$ (6.0)	$ 22.9
Total		$ (6.0)	$ 22.9
Evergy Kansas Central			
Operating revenues	Commodity	$ (6.0)	$ 22.9
Total		$ (6.0)	$ 22.9

Credit risk of the Evergy Companies' derivative instruments relates to the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. The Evergy Companies maintain credit policies and employ credit risk mitigation, such as collateral requirements or letters of credit, when necessary to minimize their overall credit risk and monitor exposure. Substantially all of the Evergy Companies' counterparty credit risk associated with derivative instruments relates to Evergy Kansas Central's non-regulated energy marketing activities. As of March 31, 2024, if counterparty groups completely failed to perform on contracts, Evergy's and Evergy Kansas Central's maximum exposure related to derivative assets was $36.4 million. As of March 31, 2024, the potential loss after the consideration of applicable master netting arrangements and collateral received for Evergy and Evergy Kansas Central was $29.4 million.

Certain of the Evergy Companies' derivative instruments contain collateral provisions that are tied to the Evergy Companies' credit ratings and may require the posting of collateral for various reasons, including if the Evergy Companies' credit ratings were to fall below investment grade. Substantially all of these derivative instruments relate to Evergy Kansas Central's non-regulated energy marketing activities. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of March 31, 2024, was $39.8 million for which Evergy and Evergy Kansas Central have posted $2.6 million collateral in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered as of March 31, 2024, Evergy and Evergy Kansas Central could be required to post an additional $37.1 million of collateral to their counterparties.

9. FAIR VALUE MEASUREMENTS

Values of Financial Instruments
GAAP establishes a hierarchical framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy levels. In addition, the Evergy Companies measure certain investments that do not have a readily determinable fair value at net asset value (NAV), which are not included in the fair value hierarchy. Further explanation of these levels and NAV is summarized below.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on public exchanges or exchange-traded derivative instruments.

Level 2 – Pricing inputs are not quoted prices in active markets but are either directly or indirectly observable. The types of assets and liabilities included in Level 2 are certain marketable debt securities, financial instruments traded in less than active markets, non-exchange traded derivative instruments with observable forward curves and options contracts.

Level 3 – Significant inputs to pricing have little or no transparency. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation. The types of assets and liabilities included in Level 3 are non-exchange traded derivative instruments for which observable market data is not available to corroborate the valuation inputs and transmission congestion rights (TCRs) in the SPP Integrated Marketplace.

NAV - Investments that do not have a readily determinable fair value are measured at NAV. These investments do not consider the observability of inputs and, therefore, they are not included within the fair value hierarchy. The Evergy Companies include in this category investments in private equity, real estate and alternative investment funds that do not have a readily determinable fair value. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments.

The Evergy Companies record cash and cash equivalents, accounts receivable and short-term borrowings on their consolidated balance sheets at cost, which approximates fair value due to the short-term nature of these instruments.

Fair Value of Long-Term Debt
The Evergy Companies measure the fair value of long-term debt using Level 2 measurements available as of the measurement date. The book value and fair value of the Evergy Companies' long-term debt are summarized in the following table.

	March 31, 2024		December 31, 2023	
	Book Value	Fair Value	Book Value	Fair Value
Long-term debt[(a)]	(millions)			
Evergy[(b)]	$ 12,469.9	$ 11,511.4	$ 11,853.3	$ 11,044.9
Evergy Kansas Central	4,581.0	4,100.7	4,580.4	4,176.6
Evergy Metro	3,217.6	2,987.7	2,924.4	2,738.8

[(a)] Includes current maturities.
[(b)] Book value as of March 31, 2024 and December 31, 2023, includes $85.7 million and $87.0 million, respectively, of fair value adjustments recorded in connection with purchase accounting for the Great Plains Energy and Evergy Kansas Central merger, which are not part of future principal payments and will amortize over the remaining life of the associated debt instrument.

Recurring Fair Value Measurements

The following tables include balances of financial assets and liabilities measured at fair value on a recurring basis.

Description	March 31, 2024	Netting	Level 1	Level 2	Level 3	NAV
Evergy Kansas Central			(millions)			
Assets						
Nuclear decommissioning trust[a]						
Domestic equity funds	$ 140.8	$ —	$ 131.0	$ —	$ —	$ 9.8
International equity funds	74.0	—	74.0	—	—	—
Core bond fund	56.2	—	56.2	—	—	—
High-yield bond fund	29.5	—	29.5	—	—	—
Emerging markets bond fund	18.2	—	18.2	—	—	—
Alternative investments fund	40.1	—	—	—	—	40.1
Real estate securities fund	16.6	—	—	—	—	16.6
Cash equivalents	0.5	—	0.5	—	—	—
Total nuclear decommissioning trust	375.9	—	309.4	—	—	66.5
Rabbi trust						
Fixed income funds	14.7	—	14.7	—	—	—
Equity funds	7.2	—	7.2	—	—	—
Combination debt/equity/other fund	1.7	—	1.7	—	—	—
Cash equivalents	0.2	—	0.2	—	—	—
Total rabbi trust	23.8	—	23.8	—	—	—
Derivative instruments - commodity contracts[b]						
Power	43.5	(9.3)	14.0	36.4	2.4	—
Natural gas	0.6	(31.7)	29.9	2.4	—	—
Total derivative assets	44.1	(41.0)	43.9	38.8	2.4	—
Total assets	443.8	(41.0)	377.1	38.8	2.4	66.5
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	42.4	(5.0)	7.3	39.7	0.4	—
Natural gas	2.3	(31.6)	31.6	2.3	—	—
Total derivative liabilities	44.7	(36.6)	38.9	42.0	0.4	—
Total liabilities	$ 44.7	$ (36.6)	$ 38.9	$ 42.0	$ 0.4	$ —
Evergy Metro						
Assets						
Nuclear decommissioning trust[a]						
Equity securities	$ 330.2	$ —	$ 330.2	$ —	$ —	$ —
Debt securities						
U.S. Treasury	47.3	—	47.3	—	—	—
State and local obligations	3.8	—	—	3.8	—	—
Corporate bonds	42.8	—	—	42.8	—	—
Foreign governments	0.1	—	—	0.1	—	—
Cash equivalents	5.8	—	5.8	—	—	—
Total nuclear decommissioning trust	430.0	—	383.3	46.7	—	—
Self-insured health plan trust[c]						
Equity securities	2.1	—	2.1	—	—	—
Debt securities	10.9	—	2.9	8.0	—	—
Cash and cash equivalents	4.8	—	4.8	—	—	—
Total self-insured health plan trust	17.8	—	9.8	8.0	—	—
Derivative instruments - commodity contracts[b]						
Power	1.6	(1.0)	—	—	2.6	—
Total derivative assets	1.6	(1.0)	—	—	2.6	—
Total assets	449.4	(1.0)	393.1	54.7	2.6	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	—	(1.0)	—	—	1.0	—
Total derivative liabilities	—	(1.0)	—	—	1.0	—
Total liabilities	$ —	$ (1.0)	$ —	$ —	$ 1.0	$ —

Description	March 31, 2024	Netting	Level 1	Level 2	Level 3	NAV
Other Evergy			(millions)			
Assets						
Rabbi trusts						
Core bond fund	$ 8.5	$ —	$ 8.5	$ —	$ —	$ —
Total rabbi trusts	8.5	—	8.5	—	—	—
Derivative instruments - commodity contracts[b]						
Power	1.9	(0.2)	—	—	2.1	—
Total derivative assets	1.9	(0.2)	—	—	2.1	—
Total assets	10.4	(0.2)	8.5	—	2.1	—
Liabilities						
Derivative instruments						
Power	—	(0.2)	—	—	0.2	—
Total derivative liabilities	—	(0.2)	—	—	0.2	—
Total liabilities	$ —	$ (0.2)	$ —	$ —	$ 0.2	$ —
Evergy						
Assets						
Nuclear decommissioning trust[a]	$ 805.9	$ —	$ 692.7	$ 46.7	$ —	$ 66.5
Rabbi trusts	32.3	—	32.3	—	—	—
Self-insured health plan trust[c]	17.8	—	9.8	8.0	—	—
Derivative instruments - commodity contracts[b]						
Power	47.0	(10.5)	14.0	36.4	7.1	—
Natural gas	0.6	(31.7)	29.9	2.4	—	—
Total derivative assets	47.6	(42.2)	43.9	38.8	7.1	—
Total assets	903.6	(42.2)	778.7	93.5	7.1	66.5
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	42.4	(6.2)	7.3	39.7	1.6	—
Natural gas	2.3	(31.6)	31.6	2.3	—	—
Total derivative liabilities	44.7	(37.8)	38.9	42.0	1.6	—
Total liabilities	$ 44.7	$ (37.8)	$ 38.9	$ 42.0	$ 1.6	$ —

Description	December 31, 2023	Netting	Level 1	Level 2	Level 3	NAV
Evergy Kansas Central			(millions)			
Assets						
Nuclear decommissioning trust[a]						
Domestic equity funds	$ 133.1	$ —	$ 123.3	$ —	$ —	$ 9.8
International equity funds	72.6	—	72.6	—	—	—
Core bond fund	56.2	—	56.2	—	—	—
High-yield bond fund	29.1	—	29.1	—	—	—
Emerging markets bond fund	18.3	—	18.3	—	—	—
Alternative investments fund	37.9	—	—	—	—	37.9
Real estate securities fund	17.2	—	—	—	—	17.2
Cash equivalents	0.7	—	0.7	—	—	—
Total nuclear decommissioning trust	365.1	—	300.2	—	—	64.9
Rabbi trust						
Fixed income funds	15.2	—	15.2	—	—	—
Equity funds	7.4	—	7.4	—	—	—
Combination debt/equity/other fund	1.7	—	1.7	—	—	—
Cash equivalents	0.2	—	0.2	—	—	—
Total rabbi trust	24.5	—	24.5	—	—	—
Derivative instruments - commodity contracts[b]						
Power	40.2	(13.8)	16.3	32.2	5.5	—
Natural gas	0.7	(73.4)	72.7	1.4	—	—
Total derivative assets	40.9	(87.2)	89.0	33.6	5.5	—
Total assets	430.5	(87.2)	413.7	33.6	5.5	64.9
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	40.3	(6.9)	9.4	34.6	3.2	—
Natural gas	0.4	(73.4)	72.6	1.2	—	—
Total derivative liabilities	40.7	(80.3)	82.0	35.8	3.2	—
Total liabilities	$ 40.7	$ (80.3)	$ 82.0	$ 35.8	$ 3.2	$ —
Evergy Metro						
Assets						
Nuclear decommissioning trust[a]						
Equity securities	$ 302.4	$ —	$ 302.4	$ —	$ —	$ —
Debt securities						
U.S. Treasury	47.9	—	47.9	—	—	—
State and local obligations	3.8	—	—	3.8	—	—
Corporate bonds	43.9	—	—	43.9	—	—
Foreign governments	0.1	—	—	0.1	—	—
Cash equivalents	3.2	—	3.2	—	—	—
Total nuclear decommissioning trust	401.3	—	353.5	47.8	—	—
Self-insured health plan trust[c]						
Equity securities	2.0	—	2.0	—	—	—
Debt securities	9.4	—	2.5	6.9	—	—
Cash and cash equivalents	4.3	—	4.3	—	—	—
Total self-insured health plan trust	15.7	—	8.8	6.9	—	—
Derivative instruments - commodity contracts[b]						
Power	—	(2.1)	—	—	2.1	—
Total derivative assets	—	(2.1)	—	—	2.1	—
Total assets	417.0	(2.1)	362.3	54.7	2.1	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	3.6	(2.1)	—	—	5.7	—
Total derivative liabilities	3.6	(2.1)	—	—	5.7	—
Total liabilities	$ 3.6	$ (2.1)	$ —	$ —	$ 5.7	$ —

Description	December 31, 2023	Netting	Level 1	Level 2	Level 3	NAV
Other Evergy			(millions)			
Assets						
Rabbi trusts						
Core bond fund	$ 8.8	$ —	$ 8.8	$ —	$ —	$ —
Total rabbi trusts	8.8	—	8.8	—	—	—
Derivative instruments - commodity contracts[b]						
Power	1.8	(1.0)	—	—	2.8	—
Total derivative assets	1.8	(1.0)	—	—	2.8	—
Total assets	10.6	(1.0)	8.8	—	2.8	—
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	—	(1.0)	—	—	1.0	—
Natural gas	1.1	—	—	1.1	—	—
Total derivative liabilities	1.1	(1.0)	—	1.1	1.0	—
Total liabilities	$ 1.1	$ (1.0)	$ —	$ 1.1	$ 1.0	$ —
Evergy						
Assets						
Nuclear decommissioning trust[a]	$ 766.4	$ —	$ 653.7	$ 47.8	$ —	$ 64.9
Rabbi trusts	33.3	—	33.3	—	—	—
Self-insured health plan trust[c]	15.7	—	8.8	6.9	—	—
Derivative instruments - commodity contracts[b]						
Power	42.0	(16.9)	16.3	32.2	10.4	—
Natural gas	0.7	(73.4)	72.7	1.4	—	—
Total derivative assets	42.7	(90.3)	89.0	33.6	10.4	—
Total assets	858.1	(90.3)	784.8	88.3	10.4	64.9
Liabilities						
Derivative instruments - commodity contracts[b]						
Power	43.9	(10.0)	9.4	34.6	9.9	—
Natural gas	1.5	(73.4)	72.6	2.3	—	—
Total derivative liabilities	45.4	(83.4)	82.0	36.9	9.9	—
Total liabilities	$ 45.4	$ (83.4)	$ 82.0	$ 36.9	$ 9.9	$ —

[a] With the exception of investments measured at NAV, fair value is based on quoted market prices of the investments held by the trust and/or valuation models.

[b] Derivative instruments classified as Level 1 consist of exchange-traded derivative instruments with fair value based on quoted market prices. Derivative instruments classified as Level 2 consist of non-exchange traded derivative instruments with observable forward curves and option contracts priced with models using observable inputs. Derivative instruments classified as Level 3 consist of non-exchange traded derivative instruments for which observable market data is not available to corroborate the valuation inputs and TCRs valued at the most recent auction price in the SPP Integrated Marketplace.

[c] Fair value is based on quoted market prices of the investments held by the trust. Debt securities classified as Level 1 are comprised of U.S. Treasury securities. Debt securities classified as Level 2 are comprised of corporate bonds, U.S. Agency, state and local obligations, and other asset-backed securities.

Certain Evergy and Evergy Kansas Central investments included in the table above are measured at NAV as they do not have readily determinable fair values. In certain situations, these investments may have redemption restrictions. The following table provides additional information on these Evergy and Evergy Kansas Central investments.

	March 31, 2024		December 31, 2023		March 31, 2024	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
Evergy Kansas Central		(millions)				
Nuclear decommissioning trust:						
Domestic equity funds	$ 9.8	$ 1.4	$ 9.8	$ 1.4	(a)	(a)
Alternative investments fund[b]	40.1	—	37.9	—	Quarterly	65 days
Real estate securities fund[b]	16.6	—	17.2	—	Quarterly	65 days
Total Evergy investments at NAV	$ 66.5	$ 1.4	$ 64.9	$ 1.4		

[a] This investment is in five long-term private equity funds that do not permit early withdrawal. Investments in these funds cannot be distributed until the underlying investments have been liquidated, which may take years from the date of initial liquidation. All funds have begun to make distributions.
[b] There is a holdback on final redemptions.

The Evergy Companies hold equity and debt investments classified as securities in various trusts including for the purposes of funding the decommissioning of Wolf Creek and for the benefit of certain retired executive officers of Evergy Kansas Central. The Evergy Companies record net realized and unrealized gains and losses on the nuclear decommissioning trusts in regulatory liabilities on their consolidated balance sheets and record net realized and unrealized gains and losses on the Evergy Companies' rabbi trusts in the consolidated statements of income and comprehensive income.

The following table summarizes the net unrealized gains (losses) for the Evergy Companies' nuclear decommissioning trusts and rabbi trusts.

Three Months Ended March 31	2024	2023
Evergy	(millions)	
Nuclear decommissioning trust - equity securities	$ 30.3	$ 29.5
Nuclear decommissioning trust - debt securities	(1.3)	2.1
Rabbi trusts - equity securities	0.4	1.6
Total	$ 29.4	$ 33.2
Evergy Kansas Central		
Nuclear decommissioning trust - equity securities	$ 8.5	$ 14.1
Rabbi trust - equity securities	0.5	1.3
Total	$ 9.0	$ 15.4
Evergy Metro		
Nuclear decommissioning trust - equity securities	$ 21.8	$ 15.4
Nuclear decommissioning trust - debt securities	(1.3)	2.1
Total	$ 20.5	$ 17.5

10. COMMITMENTS AND CONTINGENCIES

Environmental Matters

Set forth below are descriptions of contingencies related to environmental matters that may impact the Evergy Companies' operations or their financial results. Management's assessment of these contingencies, which are based on federal and state statutes and regulations, and regulatory agency and judicial interpretations and actions, has evolved over time. These laws, regulations, interpretations and actions can also change, restrict or otherwise impact the Evergy Companies' operations or financial results. The failure to comply with these laws, regulations, interpretations and actions could result in the assessment of administrative, civil and criminal penalties and the imposition of remedial requirements. The Evergy Companies believe that all of their operations are in substantial compliance with current federal, state and local environmental standards.

There are a variety of final and proposed laws and regulations that could have a material adverse effect on the Evergy Companies' operations and consolidated financial results. Due in part to the complex nature of environmental laws and regulations, the Evergy Companies are unable to assess the impact of potential changes that may develop with respect to the environmental contingencies described below.

Mercury and Air Toxics Standards (MATS)
In April 2024, the EPA finalized a rule to tighten certain aspects of the MATS rule. The EPA is lowering the emission limit for particulate matter (PM), requiring the use of PM continuous emissions monitors (CEMS) and lowering the mercury emission limit for lignite coal-fired electric generating units (EGUs). The Evergy Companies are in the process of reviewing the details of the final rule, however, the cost to comply does not appear to be material.

Ozone Interstate Transport State Implementation Plans (ITSIP)
In 2015, the EPA lowered the Ozone National Ambient Air Quality Standards (NAAQS) from 75 ppb to 70 ppb. Impacted states were required to submit ITSIPs in 2018 to comply with the "Good Neighbor Provision" of the Clean Air Act (CAA). The EPA did not act on these ITSIP submissions by the deadline established in the CAA and entered consent decrees establishing deadlines to take final action on various ITSIPs. In February 2022, the EPA published a proposed rule to disapprove the ITSIPs submitted by nineteen states including Missouri and Oklahoma. In April 2022, the EPA published a final approval of the Kansas ITSIP in the Federal Register. The Missouri Department of Natural Resources (MDNR) submitted a supplemental ITSIP to the EPA in November 2022. In February 2023, the EPA published a final rule disapproving the ITSIPs submitted by 19 states, including the final disapproval of the Missouri and Oklahoma ITSIPs. In April 2023, the Attorneys General of Missouri and Oklahoma filed Petitions for Review in the U.S. Courts of Appeals for the Eighth and Tenth Circuits, respectively, challenging the EPA's disapproval. In May 2023, the Eighth Circuit granted a stay of the EPA's disapproval of the Missouri ITSIP. Similarly, in July 2023, the Tenth Circuit granted a stay of the EPA's disapproval of the Oklahoma ITSIP. Due to uncertainty regarding the stays of the EPA's disapprovals of the Missouri and Oklahoma ITSIPs, the Evergy Companies are unable to accurately assess the impact on their operations or consolidated financial results, but the cost to comply could be material. In January 2024, the EPA proposed to disapprove the ITSIP for Kansas and four other states. The Kansas ITSIP was previously approved in April 2022. The Evergy Companies are in the process of reviewing this proposed disapproval of the Kansas ITSIP; however, the impact on the Evergy Companies' operations could be material.

Ozone Interstate Transport Federal Implementation Plans (ITFIP)
In April 2022, the EPA published in the Federal Register the proposed ITFIP to resolve outstanding "Good Neighbor" obligations with respect to the 2015 Ozone NAAQS for 26 states including Missouri and Oklahoma. This ITFIP would establish a revised Cross-State Air Pollution Rule (CSAPR) ozone season nitrogen oxide (NOx) emissions trading program for electric generating units (EGUs) beginning in 2023 and would limit ozone season NOx emissions from certain industrial stationary sources beginning in 2026. The proposed rule would also establish a new daily backstop NOx emissions rate limit for applicable coal-fired units larger than 100 MW, as well as unit-specific NOx emission rate limits for certain industrial emission units and would feature "dynamic" adjustments of emission budgets for EGUs beginning with ozone season 2025. The proposed ITFIP includes reductions to the state ozone season NOx budgets for Missouri and Oklahoma beginning in 2023 with additional reductions in future years. The Evergy Companies provided formal comments as part of the rulemaking process. In March 2023, the EPA issued the final ITFIPs for twenty-three states, including Missouri and Oklahoma, which included reduced ozone season NOx budgets for EGUs in Missouri, Oklahoma and other states, and included other features and requirements that were in the proposed version of the rule. Because the EPA's authority to impose an ITFIP for a state is triggered by the state's failure to submit an ITSIP addressing NAAQS by the statutory deadline or disapproval of an ITSIP, the EPA lacks authority under the Clean Air Act to impose an ITFIP on a state for which SIP disapprovals have been stayed by the courts. Accordingly, the EPA issued interim final rules staying the effectiveness of the ITFIP in both Missouri and Oklahoma while the stays issued by the Eighth and Tenth Circuits in the ITSIP disapproval cases remain in place. During this time, both states will continue to operate under the

existing CSAPR program. While Kansas was not originally included in the ITFIP, in January 2024, the EPA issued a proposal to include Kansas in the ITFIP. If finalized, the ITFIP for Kansas would become effective for the 2025 ozone season beginning in May 2025. The Evergy Companies are in the process of reviewing the details of this proposal; however, the impact on the Evergy Companies' operations and the cost to comply could be material.

Particulate Matter National Ambient Air Quality Standards
In March 2024, the EPA published in the Federal Register the final rule which strengthens the primary annual $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter) NAAQS. The EPA is lowering the primary annual $PM_{2.5}$ NAAQS from 12.0 µg/m3 (micrograms per cubic meter) to 9.0 µg/m3. The final rule took effect in May 2024. The Evergy Companies are in the process of reviewing this final rule, however, due to uncertainty regarding the long-term implementation of this final rule, the Evergy Companies are unable to accurately assess the impacts on their operations or consolidated financial results, but the cost to comply with lower $PM_{2.5}$ NAAQS could be material.

Regional Haze Rule
In 1999, the EPA finalized the Regional Haze Rule which aims to restore national parks and wilderness areas to pristine conditions. The rule requires states in coordination with the EPA, the National Park Service, the U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. There are 156 "Class I" areas across the U.S. that must be restored to pristine conditions by the year 2064. There are no Class I areas in Kansas, whereas Missouri has two: the Hercules-Glades Wilderness Area and the Mingo Wilderness Area. States must submit revisions to their Regional Haze Rule SIPs every ten years and the first round was due in 2007. For the second ten-year implementation period, the EPA issued a final rule revision in 2017 that allowed states to submit their SIP revisions by July 2021. The Missouri SIP revision does not require any additional reductions from the Evergy Companies' generating units in the state. MDNR submitted the Missouri SIP revision to the EPA in August 2022, however, they failed to do so by the EPA's revised submittal deadline in August 2022. As a result, in August 2022, the EPA published "finding of failure" with respect to Missouri and fourteen other states for failing to submit their Regional Haze SIP revisions by the applicable deadline. This finding of failure established a two-year deadline for the EPA to issue a Regional Haze federal implementation plan (FIP) for each state unless the state submits and the EPA approves a revised SIP that meets all applicable requirements before the EPA issues the FIP. The Kansas SIP revision requested no additional emission reductions by electric utilities based on the significant reductions that were achieved during the first implementation period. The Kansas Department of Health and Environment (KDHE) submitted the Kansas SIP revision in July 2021. In January 2024, the EPA issued a proposal to disapprove the Kansas SIP revision for failing to conduct a four-factor analysis for at least two emission sources in Kansas. If a Kansas generating unit of the Evergy Companies is selected for analysis, the possibility exists that the state or the EPA, through a revised SIP or a FIP, could determine that additional operational or physical modifications are required on the generating unit to further reduce emissions. The overall cost of those modifications could be material to the Evergy Companies.

Greenhouse Gases
Burning coal and other fossil fuels releases carbon dioxide (CO_2) and other gases referred to as greenhouse gases (GHG). Various regulations under the CAA limit CO_2 and other GHG emissions, and in addition, other measures are being imposed or offered by individual states, municipalities and regional agreements with the goal of reducing GHG emissions. In April 2024, the EPA finalized the GHG regulations and GHG guidelines that apply to new and existing fossil fuel fired EGUs. The final GHG regulation establishes CO_2 limitations on emissions from new and reconstructed stationary combustion turbines. The GHG guidelines set CO_2 emission limitations for existing coal, oil and gas-fired steam generating units. For new and reconstructed stationary combustion turbines, the emission limitations were developed by applying the Best System of Emission Reduction (BSER) to three distinct subcategories (low load, intermediate load and base load) taking into consideration the annual capacity factor of the stationary combustion turbine. For intermediate and base load stationary combustion turbines, BSER is assumed to be the utilization of highly efficient combustion turbine technology. Base load stationary combustion turbines are also required to consider the emissions reduction associated with the application of carbon capture and sequestration (CCS) beginning in 2032. For existing coal-fired EGUs, the emission limitations were established by applying the BSER to two subcategories (medium and long-term). For medium-term existing coal-fired units, which are units

retiring between 2032 and 2038, the BSER established emission limitation is based on co-firing natural gas beginning in 2030. For units operating in 2039 and after, BSER is the application of CCS starting in 2032.

The Evergy Companies are in the process of reviewing the final GHG regulation and guidelines however, due to uncertainty regarding the implementation of these final rules, the Evergy Companies are unable to accurately assess the impacts on their operations or consolidated financial results, but the cost to comply could be material.

Water
The Evergy Companies discharge some of the water used in generation and other operations containing substances deemed to be pollutants. In April 2024, the EPA finalized an update to the ELG to address the vacated limitations and prior reviews of the existing rule by the current administration. Flue Gas Desulfurization (FGD) wastewater, bottom ash transport wastewater (BATW), coal residual leachate (CRL), and legacy wastewater are addressed in the rulemaking. FGD, BATW and CRL at operating facilities are required to achieve zero liquid discharge as soon as feasible and no later than December 2029. The Evergy Companies have reviewed the modifications to limitations on FGD wastewater and bottom ash transport water and the Evergy Companies do not believe the impact to be material. The Evergy Companies are reviewing the limitations on CRL, its impact on their operations and financial results and believe the cost to comply could be material.

Regulation of Coal Combustion Residuals (CCRs)
In the course of operating their coal generation plants, the Evergy Companies produce CCRs, including fly ash, gypsum and bottom ash. The EPA published a rule to regulate CCRs in April 2015 that requires additional CCR handling, processing and storage equipment and closure of certain ash disposal units. In January 2022, the EPA published proposed determinations for facilities that filed closure extensions for unlined or clay-lined CCR units. These proposed determinations include various interpretations of the CCR regulations and compliance expectations that may impact all owners of CCR units. These interpretations could require modified compliance plans such as different methods of CCR unit closure. Additionally, more stringent remediation requirements for units that are in corrective action or forced to go into corrective action are possible. In April 2022, the Utility Solid Waste Activities Group (USWAG) and other interested parties filed similar petitions in the D.C. Circuit challenging the EPA's legal positions regarding the CCR rule determinations proposed in January 2022. The cost to comply with these proposed determinations by the EPA could be material.

In April 2024, the EPA finalized an expansion to the CCR regulation focused on legacy surface impoundments and historic placements of CCR. This regulation expands applicability of the 2015 CCR regulation to two newly defined types of CCR disposal units. The Evergy Companies are reviewing the final regulation and anticipate having additional CCR units requiring evaluation and potential remediation. The cost to comply with this regulation by the EPA could be material.

The Evergy Companies have recorded asset retirement obligations (AROs) for their current estimates for the closure of ash disposal ponds and landfills, but the revision of these AROs may be required in the future due to changes in existing CCR regulations, the results of groundwater monitoring of CCR units or changes in interpretation of existing CCR regulations or changes in the timing or cost to close ash disposal ponds and landfills. The revision of AROs for regulated operations has no income statement impact due to the deferral of the adjustments through a regulatory asset. If revisions to these AROs are necessary, the impact on the Evergy Companies' operations or consolidated financial results could be material.

11. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

In the normal course of business, Evergy Kansas Central, Evergy Metro and Evergy Missouri West engage in related party transactions with one another. A summary of these transactions and the amounts associated with them is provided below.

Jointly-Owned Plants and Shared Services
Employees of Evergy Kansas Central and Evergy Metro manage Evergy Missouri West's business and operate its facilities at cost, including Evergy Missouri West's 18% ownership interest in Evergy Metro's Iatan Nos. 1 and 2.

Employees of Evergy Kansas Central manage JEC and operate its facilities at cost, including Evergy Missouri West's 8% ownership interest in JEC. Employees of Evergy Metro manage La Cygne Station and operate its facilities at cost, including Evergy Kansas Central's 50% interest in La Cygne Station. Employees of Evergy Metro and Evergy Kansas Central also provide one another with shared service support, including costs related to human resources, information technology, accounting and legal services.

The operating expenses and capital costs billed for jointly-owned plants and shared services are detailed in the following table.

Three Months Ended March 31	2024	2023
	(millions)	
Evergy Kansas Central billings to Evergy Missouri West	$ 7.1	$ 6.2
Evergy Metro billings to Evergy Missouri West	28.2	26.8
Evergy Kansas Central billings to Evergy Metro	11.3	10.9
Evergy Metro billings to Evergy Kansas Central	32.4	28.9

Related Party Net Receivables and Payables
The following table summarizes Evergy Kansas Central's and Evergy Metro's related party net receivables and payables.

	March 31 2024	December 31 2023
Evergy Kansas Central	(millions)	
Net payable to Evergy	$ (331.2)	$ (274.5)
Net payable to Evergy Metro	(28.3)	(19.6)
Net receivable from Evergy Missouri West	8.9	11.3
Evergy Metro		
Net receivable from Evergy	$ 20.6	$ 15.9
Net receivable from Evergy Kansas Central	28.3	19.6
Net receivable from Evergy Missouri West	80.6	91.9

Money Pool
Evergy Kansas Central, Evergy Metro and Evergy Missouri West are authorized to participate in the Evergy, Inc. money pool, which is an internal financing arrangement in which funds may be lent on a short-term basis between Evergy Kansas Central, Evergy Metro, Evergy Missouri West and Evergy, Inc. Evergy, Inc. can lend but not borrow under the money pool.

As of March 31, 2024 and December 31, 2023, Evergy Metro had no outstanding receivables or payables under the money pool. As of March 31, 2024, Evergy Kansas Central had a $319.2 million outstanding payable to Evergy, Inc. under the money pool. As of December 31, 2023, Evergy Kansas Central had a $261.4 million outstanding payable to Evergy, Inc. under the money pool.

Tax Allocation Agreement

Evergy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. The following table summarizes Evergy Kansas Central's and Evergy Metro's income taxes receivable from (payable to) Evergy.

	March 31 2024	December 31 2023
Evergy Kansas Central	(millions)	
Income taxes receivable from Evergy	$ 3.9	$ 11.5
Evergy Metro		
Income taxes payable to Evergy	$ (12.1)	$ (6.8)

12. VARIABLE INTEREST ENTITIES

In determining the primary beneficiary of a VIE, the Evergy Companies assess the entity's purpose and design, including the nature of the entity's activities and the risks that the entity was designed to create and pass through to its variable interest holders. A reporting enterprise is deemed to be the primary beneficiary of a VIE if it has (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses or right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary of a VIE is required to consolidate the VIE.

All involvement with entities by the Evergy Companies is assessed to determine whether such entities are VIEs and, if so, whether or not the Evergy Companies are the primary beneficiaries of the entities. The Evergy Companies also continuously assess whether they are the primary beneficiary of the VIE with which they are involved. Prospective changes in facts and circumstances may cause identification of the primary beneficiary to be reconsidered.

Evergy Missouri West Storm Funding

In 2022, Evergy Missouri West created Evergy Missouri West Storm Funding solely for the purpose of recovering extraordinary fuel and purchased power costs incurred as part of the February 2021 winter weather event. In February 2024, Evergy Missouri West Storm Funding issued, at a discount, $331.1 million of 5.10% Securitized Bonds with a final payment scheduled for 2038, maturing in 2040. The obligations of Evergy Missouri West Storm Funding's Securitization Bonds are repaid through charges imposed on customers in Evergy Missouri West's service territory and collected by Evergy Missouri West on behalf of Evergy Missouri West Storm Funding. Creditors of Evergy Missouri West have no recourse to any assets or revenues of Evergy Missouri West Storm Funding, and the bondholders have no recourse to the general credit of Evergy Missouri West. See Note 4 for additional information regarding the February 2021 winter weather event securitization.

Evergy Missouri West Storm Funding is considered a VIE primarily because, as described above, Evergy Missouri West has the power to direct the activities of Evergy Missouri West Storm Funding that most significantly impact economic performance and Evergy Missouri West has the obligation to absorb losses or the right to receive benefits from Evergy Missouri West Storm Funding that could potentially be significant. Therefore, Evergy Missouri West is considered the primary beneficiary and consolidates Evergy Missouri West Storm Funding.

The following table summarizes the impact of Evergy Missouri West Storm Funding on Evergy's consolidated balance sheet as of March 31, 2024. There was no impact on Evergy's consolidated balance sheet as of December 31, 2023.

		March 31 2024
Evergy		(millions)
Current assets		
Regulatory assets	$	15.2
Other assets		
Regulatory assets		306.5
Other		1.7
Current liabilities		
Current maturities of long-term debt		11.5
Accrued interest		1.7
Long-term liabilities		
Long-term debt, net		311.5

13. TAXES

Components of income tax expense are detailed in the following tables.

Evergy

Three Months Ended March 31		**2024**		**2023**
Current income taxes		(millions)		
Federal	$	10.2	$	5.0
State		8.1		4.7
Total		18.3		9.7
Deferred income taxes				
Federal		(2.5)		7.7
State		(6.7)		(3.3)
Total		(9.2)		4.4
Investment tax credit amortization		(1.8)		(1.7)
Income tax expense	$	7.3	$	12.4

Evergy Kansas Central

Three Months Ended March 31		**2024**		**2023**
Current income taxes		(millions)		
Federal	$	4.3	$	18.1
State		3.1		2.0
Total		7.4		20.1
Deferred income taxes				
Federal		(2.5)		(10.0)
State		(1.8)		(0.7)
Total		(4.3)		(10.7)
Investment tax credit amortization		(1.0)		(1.0)
Income tax expense	$	2.1	$	8.4

Evergy Metro

Three Months Ended March 31	2024	2023
Current income taxes	(millions)	
Federal	$ 2.0	$ (5.1)
State	3.3	1.6
Total	5.3	(3.5)
Deferred income taxes		
Federal	4.8	12.4
State	(2.9)	(1.2)
Total	1.9	11.2
Investment tax credit amortization	(0.8)	(0.8)
Income tax expense	$ 6.4	$ 6.9

Effective Income Tax Rates

Effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

Evergy

Three Months Ended March 31	2024	2023
Federal statutory income tax	21.0 %	21.0 %
COLI policies	(1.2)	(1.4)
State income taxes	0.6	0.6
Flow through depreciation for plant-related differences	(8.3)	(7.7)
Federal tax credits	(6.6)	(3.5)
Non-controlling interest	(0.3)	(0.3)
AFUDC equity	(0.3)	(0.6)
Amortization of federal investment tax credits	(0.6)	(0.6)
Stock compensation	0.4	0.1
Officer compensation limitation	0.8	0.2
Other	0.1	0.1
Effective income tax rate	5.6 %	7.9 %

Evergy Kansas Central

Three Months Ended March 31	2024	2023
Federal statutory income tax	21.0 %	21.0 %
COLI policies	(2.0)	(2.4)
State income taxes	0.6	0.7
Flow through depreciation for plant-related differences	(5.4)	(4.0)
Federal tax credits	(10.9)	(6.3)
Non-controlling interest	(0.5)	(0.5)
AFUDC equity	(0.5)	(0.5)
Amortization of federal investment tax credits	(0.4)	(0.4)
Stock compensation	(0.1)	(0.2)
Other	0.1	—
Effective income tax rate	1.9 %	7.4 %

Evergy Metro		
Three Months Ended March 31	**2024**	**2023**
Federal statutory income tax	21.0 %	21.0 %
COLI policies	(0.1)	(0.1)
State income taxes	0.9	0.6
Flow through depreciation for plant-related differences	(7.7)	(8.1)
Federal tax credits	(0.6)	(0.2)
AFUDC equity	—	(0.9)
Amortization of federal investment tax credits	(0.9)	(0.9)
Stock compensation	1.9	1.0
Officer compensation limitation	1.9	0.6
Other	—	(0.1)
Effective income tax rate	16.4 %	12.9 %

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) should be read in conjunction with the consolidated financial statements and accompanying notes in this combined Quarterly Report on Form 10-Q and the Evergy Companies' combined 2023 Form 10-K. None of the registrants make any representation as to information related solely to Evergy, Evergy Kansas Central or Evergy Metro other than itself.

EVERGY, INC.

EXECUTIVE SUMMARY

Evergy is a public utility holding company incorporated in 2017 and headquartered in Kansas City, Missouri. Evergy operates primarily through the following wholly-owned direct subsidiaries listed below.

- Evergy Kansas Central is an integrated, regulated electric utility that provides electricity to customers in the state of Kansas. Evergy Kansas Central has one active wholly-owned subsidiary with significant operations, Evergy Kansas South.
- Evergy Metro is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas.
- Evergy Missouri West is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.
- Evergy Transmission Company owns 13.5% of Transource with the remaining 86.5% owned by AEP Transmission Holding Company, LLC, a subsidiary of AEP. Transource is focused on the development of competitive electric transmission projects. Evergy Transmission Company accounts for its investment in Transource under the equity method.

Evergy Kansas Central also owns a 50% interest in Prairie Wind, which is a joint venture between Evergy Kansas Central and subsidiaries of AEP and Berkshire Hathaway Energy Company. Prairie Wind owns a 108-mile, 345 kV double-circuit transmission line that provides transmission service in the SPP. Evergy Kansas Central accounts for its investment in Prairie Wind under the equity method.

Evergy Kansas Central, Evergy Kansas South, Evergy Metro and Evergy Missouri West conduct business in their respective service territories using the name Evergy. Collectively, the Evergy Companies have approximately 15,800 MWs of owned generating capacity and renewable power purchase agreements and engage in the generation, transmission, distribution and sale of electricity to approximately 1.7 million customers in the states of

Kansas and Missouri. The Evergy Companies assess financial performance and allocate resources on a consolidated basis (i.e., operate in one segment).

Evergy Missouri West 2024 Rate Case Proceeding
In February 2024, Evergy Missouri West filed an application with the MPSC to request an increase to its retail revenues of approximately $104 million. Evergy Missouri West's request reflected a return on equity of 10.5% (with a capital structure composed of 52% equity) and increases related to the recovery of infrastructure investments made to improve reliability and enhance customer service and the inclusion of certain costs related to Dogwood and Crossroads, two natural gas plants. An evidentiary hearing in the case is scheduled to occur beginning in late September 2024 and new rates are expected to be effective in January 2025.

Evergy Missouri West Securitized Bonds
In February 2024, Evergy Missouri West Storm Funding issued, at a discount, $331.1 million of 5.10% Securitized Bonds in order to recover the extraordinary fuel and purchased power costs incurred as part of the February 2021 winter weather event. See Notes 4 and 7 to the consolidated financial statements for additional information regarding the securitized bonds.

Natural Gas Plant Investment
In April 2024, Evergy Missouri West purchased a joint ownership interest representing approximately 145 MW in Dogwood, an operational natural gas combined cycle facility located in Missouri, for approximately $60 million. The purchase was subject to terms and conditions listed in a stipulation and agreement approved by the MPSC allowing Evergy Missouri West to recover in rates a return of and return on the original cost, net of accumulated deprecation, of Dogwood. Evergy Missouri West shall also be allowed to recover in rates over two years a return of, but not a return on, the amount of the purchase price paid in excess of the original cost, net of accumulated depreciation, of Dogwood. In addition, net revenues generated from Evergy Missouri West's ownership of Dogwood from the date of closing to the date new rates become effective in Evergy Missouri West's current rate case shall not impact rates and shall be retained by Evergy Missouri West and reduce the amount of the purchase price paid in excess of the original cost, net of accumulated depreciation, of Dogwood to be recovered from customers.

Kansas Legislation
In April 2024, Kansas H.B. 2527 was signed into law by the Governor of Kansas. Most notably, H.B. 2527 includes a plant-in service accounting (PISA) provision that can be elected by Kansas electric public utilities to defer and recover as regulatory assets 90% of depreciation expense and associated return on investment linked to qualifying electric plants in service. Qualifying electric plant includes all rate base additions by an electric public utility, but not including transmission facilities or new electric generating units. The deferred depreciation and return on the associated regulatory asset are required to be included in determining the utility's rate base during subsequent general rate proceedings. The return on the deferred regulatory asset balances will be calculated using the weighted average cost of capital. Utilities that elect the PISA provision can make qualifying deferrals of depreciation and return from July 2024 through December 2030. Evergy Kansas Central and Evergy Metro expect to elect the PISA provision in their Kansas jurisdictions.

Additionally, the bill establishes new mechanisms for the recovery of costs associated with new gas-fired generating units. If the KCC decides investment in a new gas-fired generating unit is reasonable, the utility would be able to recover the return on 100% of the associated construction costs at its weighted average cost of capital. The cost recovery from customers could begin a year after construction begins. Rates could be adjusted every six months until new base rates reflecting the plant's costs are established.

In April 2024, Kansas S.B. 410 was signed into law by the Governor of Kansas. Most notably, S.B. 410 includes an exemption from all property and ad valorem taxes on certain electric generation facilities for which construction or installation begins on or after January 1, 2025.

Regulatory Proceedings
See Note 4 to the consolidated financial statements for information regarding other regulatory proceedings.

Wolf Creek Refueling Outage
Wolf Creek's most recent refueling outage began in March 2024 and the unit is expected to return to service in May 2024.

Earnings Overview
The following table summarizes Evergy's net income and diluted earnings per common share (EPS).

Three Months Ended March 31	2024	Change	2023
	(millions, except per share amounts)		
Net income attributable to Evergy, Inc.	$ 122.7	$ (19.9)	$ 142.6
Earnings per common share, diluted	0.53	(0.09)	0.62

Net income attributable to Evergy, Inc. decreased for the three months ended March 31, 2024, compared to the same period in 2023, primarily due to higher depreciation and taxes other than income tax expense in the first quarter of 2024, 2023 mark-to-market gains related to forward contracts for natural gas and electricity and higher transmission and distribution expense; partially offset by new Evergy Kansas Central retail rates effective in December 2023, lower pension non-service costs and lower income tax expense.

Diluted EPS decreased for the three months ended March 31, 2024, compared to the same period in 2023, primarily due to the decrease in net income attributable to Evergy, Inc. discussed above.

For additional information regarding the change in net income, refer to the Evergy Results of Operations section within this MD&A.

Non-GAAP Measures
Evergy Utility Gross Margin (non-GAAP)
Utility gross margin (non-GAAP) is a financial measure that is not calculated in accordance with GAAP. Utility gross margin (non-GAAP), as used by the Evergy Companies, is defined as operating revenues less fuel and purchased power costs and amounts billed by the SPP for network transmission costs. Expenses for fuel and purchased power costs, offset by wholesale sales margin, are subject to recovery through cost adjustment mechanisms. As a result, changes in fuel and purchased power costs are offset in operating revenues with minimal impact on net income. In addition, SPP network transmission costs fluctuate primarily due to investments by SPP members for upgrades to the transmission grid within the SPP RTO. As with fuel and purchased power costs, changes in SPP network transmission costs are mostly reflected in the prices charged to customers with minimal impact on net income. The Evergy Companies' definition of utility gross margin (non-GAAP) may differ from similar terms used by other companies.

Utility gross margin (non-GAAP) is intended to aid an investor's overall understanding of results. Management believes that utility gross margin (non-GAAP) provides a meaningful basis for evaluating the Evergy Companies' operations across periods because utility gross margin (non-GAAP) excludes the revenue effect of fluctuations in fuel and purchased power costs and SPP network transmission costs. Utility gross margin (non-GAAP) is used internally to measure performance against budget and in reports for management and the Evergy Board. Utility gross margin (non-GAAP) should be viewed as a supplement to, and not a substitute for, gross margin, which is the most directly comparable financial measure prepared in accordance with GAAP. Gross margin under GAAP is defined as the excess of sales over cost of goods sold.

Utility gross margin (non-GAAP) differs from the GAAP definition of gross margin due to the exclusion of operating and maintenance expenses determined to be directly attributable to revenue-producing activities, depreciation and amortization and taxes other than income tax. See the Evergy Companies' Results of Operations for a reconciliation of utility gross margin (non-GAAP) to gross margin, the most comparable GAAP measure.

Adjusted Earnings (non-GAAP) and Adjusted EPS (non-GAAP)

Management believes that adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are representative measures of Evergy's recurring earnings, assists in the comparability of results and is consistent with how management reviews performance.

Evergy's adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) for the three months ended March 31, 2024 were $124.7 million or $0.54 per share. For the three months ended March 31, 2023, Evergy's adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) were $136.1 million or $0.59 per share.

In addition to net income attributable to Evergy, Inc. and diluted EPS, Evergy's management uses adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) to evaluate earnings and EPS without:

i. the mark-to-market impacts of economic hedges related to Evergy Kansas Central's 8% ownership share of JEC; and
ii. the costs resulting from non-regulated energy marketing margins from the February 2021 winter weather event.

Adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are intended to aid an investor's overall understanding of results. Management believes that adjusted earnings (non-GAAP) provides a meaningful basis for evaluating Evergy's operations across periods because it excludes certain items that management does not believe are indicative of Evergy's ongoing performance or that can create period to period earnings volatility.

Adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are used internally to measure performance against budget and in reports for management and the Evergy Board. Adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP) are financial measures that are not calculated in accordance with GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to Evergy, Inc. and diluted EPS as determined in accordance with GAAP and adjusted earnings (non-GAAP) and adjusted EPS (non-GAAP), respectively.

	Earnings (Loss)	Earnings (Loss) per Diluted Share	Earnings (Loss)	Earnings (Loss) per Diluted Share
Three Months Ended March 31	**2024**		**2023**	
	(millions, except per share amounts)			
Net income attributable to Evergy, Inc.	$ 122.7	$ 0.53	$ 142.6	$ 0.62
Non-GAAP reconciling items:				
Mark-to-market impact of JEC economic hedges, pre-tax[a]	2.6	0.01	(8.4)	(0.04)
Non-regulated energy marketing costs related to February 2021 winter weather event, pre-tax[b]	—	—	0.1	—
Income tax (benefit) expense[c]	(0.6)	—	1.8	0.01
Adjusted earnings (non-GAAP)	$ 124.7	$ 0.54	$ 136.1	$ 0.59

[a] Reflects mark-to-market gains or losses related to forward contracts for natural gas and electricity entered into as economic hedges against fuel price volatility related to Evergy Kansas Central's 8% ownership share of JEC that are included in operating revenues on the consolidated statements of comprehensive income.
[b] Reflects non-regulated energy marketing incentive compensation costs related to the February 2021 winter weather event that are included in operating and maintenance expense on the consolidated statements of comprehensive income.
[c] Reflects an income tax effect calculated at a statutory rate of approximately 22%.

ENVIRONMENTAL MATTERS

See Note 10 to the consolidated financial statements for information regarding environmental matters.

RELATED PARTY TRANSACTIONS

See Note 11 to the consolidated financial statements for information regarding related party transactions.

EVERGY RESULTS OF OPERATIONS

The following table summarizes Evergy's comparative results of operations.

Three Months Ended March 31	2024	Change	2023
		(millions)	
Operating revenues	$ 1,331.0	$ 34.2	$ 1,296.8
Fuel and purchased power	376.4	22.2	354.2
SPP network transmission costs	72.7	(8.5)	81.2
Operating and maintenance	231.5	15.2	216.3
Depreciation and amortization	276.1	12.7	263.4
Taxes other than income tax	114.1	11.7	102.4
Income from operations	260.2	(19.1)	279.3
Other income, net	4.3	4.3	—
Interest expense	133.2	10.1	123.1
Income tax expense	7.3	(5.1)	12.4
Equity in earnings of equity method investees, net of income taxes	1.8	(0.1)	1.9
Net income	125.8	(19.9)	145.7
Less: Net income attributable to noncontrolling interests	3.1	—	3.1
Net income attributable to Evergy, Inc.	$ 122.7	$ (19.9)	$ 142.6

Gross Margin (GAAP) and Utility Gross Margin (non-GAAP)

The following table summarizes Evergy's gross margin (GAAP) and MWhs sold and reconciles Evergy's gross margin (GAAP) to Evergy's utility gross margin (non-GAAP). See "Executive Summary - Non-GAAP Measures", above for additional information regarding gross margin (GAAP) and utility gross margin (non-GAAP).

	Revenues and Expenses			MWhs Sold		
Three Months Ended March 31	**2024**	**Change**	**2023**	**2024**	**Change**	**2023**
Retail revenues		(millions)			(thousands)	
Residential	$ 479.0	$ 20.4	$ 458.6	3,742	1	3,741
Commercial	432.7	2.7	430.0	4,290	(21)	4,311
Industrial	160.4	1.3	159.1	2,047	(17)	2,064
Other retail revenues	11.9	0.6	11.3	27	(4)	31
Total electric retail	1,084.0	25.0	1,059.0	10,106	(41)	10,147
Wholesale revenues	71.0	0.6	70.4	3,294	(254)	3,548
Transmission revenues	115.4	9.6	105.8	N/A	N/A	N/A
Other revenues	60.6	(1.0)	61.6	N/A	N/A	N/A
Operating revenues	1,331.0	34.2	1,296.8	13,400	(295)	13,695
Fuel and purchased power	(376.4)	(22.2)	(354.2)			
SPP network transmission costs	(72.7)	8.5	(81.2)			
Operating and maintenance[(a)]	(135.9)	(17.7)	(118.2)			
Depreciation and amortization	(276.1)	(12.7)	(263.4)			
Taxes other than income tax	(114.1)	(11.7)	(102.4)			
Gross margin (GAAP)	**355.8**	**(21.6)**	**377.4**			
Operating and maintenance[(a)]	135.9	17.7	118.2			
Depreciation and amortization	276.1	12.7	263.4			
Taxes other than income tax	114.1	11.7	102.4			
Utility gross margin (non-GAAP)	**$ 881.9**	**$ 20.5**	**$ 861.4**			

[(a)] Operating and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operating and maintenance expenses at generating units and transmission and distribution operating and maintenance expenses and have been separately presented in order to calculate gross margin as defined under GAAP. These amounts exclude general and administrative expenses not directly attributable to revenue-producing activities of $95.6 million and $98.1 million for the three months ended March 31, 2024 and 2023, respectively.

Evergy's gross margin (GAAP) decreased $21.6 million for the three months ended March 31, 2024, compared to the same period in 2023 and Evergy's utility gross margin (non-GAAP) increased $20.5 million for the three months ended March 31, 2024, compared to the same period in 2023, both measures were driven by:

- an $11.0 million decrease due to 2023 mark-to-market gains related to forward contracts for natural gas and electricity entered into as economic hedges against fuel price volatility related to Evergy Kansas Central's 8% ownership share of JEC; partially offset by
- a $31.5 million net increase primarily from new retail rates in Kansas effective in December 2023 consisting of $39.9 million primarily from higher Evergy Kansas Central retail rates, partially offset by $6.7 million primarily from lower Evergy Metro retail rates.

Additionally, the decrease in Evergy's gross margin (GAAP) was also driven by:

- a $17.7 million increase in operating and maintenance expenses which are determined to be directly attributable to revenue producing activities primarily driven by a $10.4 million increase in transmission and distribution operating and maintenance expenses and a $4.3 million increase in plant operating and maintenance expense at Wolf Creek as further described below;
- a $12.7 million increase in depreciation and amortization as further described below; and
- an $11.7 million increase in taxes other than income tax as further described below.

Operating and Maintenance
Evergy's operating and maintenance expense increased $15.2 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $10.4 million increase in transmission and distribution operating and maintenance expenses primarily at Evergy Kansas Central driven by higher labor expense primarily due to a decrease in labor capitalization and higher employee headcount; and
- a $4.3 million increase in plant operating and maintenance expense at Wolf Creek at Evergy Kansas Central and Evergy Metro primarily due to higher material costs.

Depreciation and Amortization
Evergy's depreciation and amortization expense increased $12.7 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $7.4 million increase primarily due to a change in depreciation rates as a result of Evergy Kansas Central's and Evergy Metro's 2023 rate cases effective in December 2023; and
- a $5.3 million increase primarily due to capital additions.

Taxes Other than Income Tax
Evergy's taxes other than income tax increased $11.7 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by

- a $7.5 million increase at Evergy Kansas Central primarily due to the rebasing of property taxes as a result of Evergy Kansas Central's 2023 rate case effective in December 2023; and
- a $3.8 million increase at Evergy Metro primarily due to an increase in property taxes primarily driven by higher assessed property valuations.

Other Income, Net
Evergy's other income, net increased $4.3 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $10.2 million decrease in pension non-service costs primarily due to the resetting of pension expense in retail rates as a result of Evergy Kansas Central's and Evergy Metro's 2023 rate cases effective in December 2023; partially offset by
- a $3.8 million decrease in investment earnings primarily driven by a $2.0 million decrease in interest and dividend income primarily due to an decrease in carrying charges related to Evergy Missouri West's costs associated with the February 2021 winter weather event to be recovered through securitized bonds issued in February 2024; and
- a $3.5 million decrease due to recording lower Evergy Kansas Central corporate-owned life insurance (COLI) benefits in 2024.

Interest Expense
Evergy's interest expense increased $10.1 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $15.8 million increase due to the issuance of Evergy, Inc.'s $1.4 billion of 4.50% Convertible Notes in December 2023; and
- a $4.6 million increase due to the issuance of Evergy Kansas Central's $400.0 million of 5.70% First Mortgage Bonds (FMBs) in March 2023; partially offset by
- a $9.7 million decrease in interest expense on short-term borrowings primarily due to lower short-term debt balances in 2024.

Income Tax Expense
Evergy's income tax expense decreased $5.1 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by lower Evergy Metro pre-tax income in the first quarter of 2024.

LIQUIDITY AND CAPITAL RESOURCES

Evergy relies primarily upon cash from operations, short-term borrowings, long-term debt and equity issuances and its existing cash and cash equivalents to fund its capital requirements. Evergy's capital requirements primarily consist of capital expenditures, payment of contractual obligations and other commitments, and the payment of dividends to shareholders. See the Evergy Companies' combined 2023 Form 10-K for more information on Evergy's sources and uses of cash.

Short-Term Borrowings
As of March 31, 2024, Evergy had $1,406.8 million of available borrowing capacity under its master credit facility. The available borrowing capacity under the master credit facility consisted of $199.3 million for Evergy, Inc., $487.5 million for Evergy Kansas Central, $337.0 million for Evergy Metro and $383.0 million for Evergy Missouri West. The Evergy Companies' borrowing capacity under the master credit facility also supports their issuance of commercial paper. See Note 6 to the consolidated financial statements for more information regarding the master credit facility.

Along with cash flows from operations and receivable sales facilities, Evergy generally uses borrowings under its master credit facility and the issuance of commercial paper to meet its day-to-day cash flow requirements. Evergy may also utilize these short-term borrowings to repay maturing long-term debt until the long-term debt is able to be refinanced. Evergy believes that its existing cash on hand and available borrowing capacity under its master credit facility provide sufficient liquidity for its existing capital requirements.

Significant Debt Issuances
See Note 7 to the consolidated financial statements for information regarding significant debt issuances.

Credit Ratings
In May 2024, Moody's Investor Service changed Evergy Missouri West's outlook from Stable to Negative, and affirmed credit ratings as detailed in the following table.

	Moody's Investors Service[(a)]
Evergy Missouri West	
Corporate Credit Rating	Baa2
Senior Secured Debt	A3
Commercial Paper	P-2

[(a)]A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

Pensions
For the three months ended March 31, 2024, Evergy made no cash pension contributions. Evergy expects to make cash pension contributions of $38.6 million in 2024. For the three months ended March 31, 2024, Evergy made post-retirement benefit contributions of $0.4 million. Evergy expects to make additional post-retirement benefit contributions of $0.4 million in 2024. See Note 5 to the consolidated financial statements for additional information on Evergy's pension and post-retirement plans.

Debt Covenants
As of March 31, 2024, Evergy was in compliance with all debt covenants under the master credit facility and certain debt instruments that contain restrictions that require the maintenance of certain capitalization and leverage ratios. See Note 6 to the consolidated financial statements for more information.

Cash Flows

The following table presents Evergy's cash flows from operating, investing and financing activities.

Three Months Ended March 31	2024	2023
	(millions)	
Cash Flows from Operating Activities	$ 317.3	$ 362.9
Cash Flows used in Investing Activities	(583.2)	(496.9)
Cash Flows from Financing Activities	303.6	137.2

Cash Flows from Operating Activities

Evergy's cash flows from operating activities decreased $45.6 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by a decrease in cash receipts for retail electric sales in 2024 primarily due to the collection of lower December receivables in January 2024 compared to the same period in 2023.

Cash Flows used in Investing Activities

Evergy's cash flows used in investing activities increased $86.3 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $90.9 million increase in additions to property, plant and equipment due to increases at Evergy Kansas Central and Evergy Missouri West of $53.6 million and $39.2 million, respectively, primarily due to increased spending for a variety of capital projects including transmission and distribution projects related to grid resiliency and other infrastructure improvements.

Cash Flows from Financing Activities

Evergy's cash flows from financing activities increased $166.4 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $300.0 million increase due to lower retirements of long-term debt, net due to Evergy Metro's repayment of $300.0 million of 3.15% Senior Notes in March 2023; partially offset by
- a $74.5 million decrease in short-term debt borrowings due to lower commercial paper borrowings for the first quarter of 2024; and
- a $67.6 million decrease in proceeds from long-term debt, net due to Evergy Kansas Central's issuance of $400.0 million of 5.70% FMBs in March 2023; partially offset by Evergy Missouri West's issuance of $331.1 million of 5.10% Securitized Bonds in February 2024.

EVERGY KANSAS CENTRAL, INC.

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The below results of operations and related discussion for Evergy Kansas Central is presented in a reduced disclosure format in accordance with General Instruction (H)(2)(a) to Form 10-Q.

The following table summarizes Evergy Kansas Central's comparative results of operations.

Three Months Ended March 31	2024	Change	2023
		(millions)	
Operating revenues	$ 693.2	$ 14.6	$ 678.6
Fuel and purchased power	138.6	(5.8)	144.4
SPP network transmission costs	72.7	(8.5)	81.2
Operating and maintenance	116.3	8.7	107.6
Depreciation and amortization	139.1	15.0	124.1
Taxes other than income tax	63.2	7.5	55.7
Income from operations	163.3	(2.3)	165.6
Other income, net	5.4	4.8	0.6
Interest expense	55.8	3.4	52.4
Income tax expense	2.1	(6.3)	8.4
Equity in earnings of equity method investees, net of income taxes	0.8	(0.2)	1.0
Net income	111.6	5.2	106.4
Less: Net income attributable to noncontrolling interests	3.1	—	3.1
Net income attributable to Evergy Kansas Central, Inc.	$ 108.5	$ 5.2	$ 103.3

Evergy Kansas Central Gross Margin (GAAP) and Utility Gross Margin (non-GAAP)

The following table summarizes Evergy Kansas Central's gross margin (GAAP) and MWhs sold and reconciles Evergy Kansas Central's gross margin (GAAP) to Evergy Kansas Central's utility gross margin (non-GAAP). See "Executive Summary - Non-GAAP Measures" for additional information regarding gross margin (GAAP) and utility gross margin (non-GAAP).

	Revenues and Expenses			MWhs Sold		
Three Months Ended March 31	**2024**	**Change**	**2023**	**2024**	**Change**	**2023**
Retail revenues		(millions)			(thousands)	
Residential	$ 214.3	$ 22.2	$ 192.1	1,501	49	1,452
Commercial	183.6	5.5	178.1	1,658	(14)	1,672
Industrial	106.0	(2.5)	108.5	1,274	(45)	1,319
Other retail revenues	6.1	1.8	4.3	10	—	10
Total electric retail	510.0	27.0	483.0	4,443	(10)	4,453
Wholesale revenues	68.1	0.5	67.6	2,546	(98)	2,644
Transmission revenues	108.9	8.3	100.6	N/A	N/A	N/A
Other revenues	6.2	(21.2)	27.4	N/A	N/A	N/A
Operating revenues	693.2	14.6	678.6	6,989	(108)	7,097
Fuel and purchased power	(138.6)	5.8	(144.4)			
SPP network transmission costs	(72.7)	8.5	(81.2)			
Operating and maintenance [(a)]	(65.7)	(11.8)	(53.9)			
Depreciation and amortization	(139.1)	(15.0)	(124.1)			
Taxes other than income tax	(63.2)	(7.5)	(55.7)			
Gross margin (GAAP)	**213.9**	**(5.4)**	**219.3**			
Operating and maintenance [(a)]	65.7	11.8	53.9			
Depreciation and amortization	139.1	15.0	124.1			
Taxes other than income tax	63.2	7.5	55.7			
Utility gross margin (non-GAAP)	**$ 481.9**	**$ 28.9**	**$ 453.0**			

[(a)] Operating and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operating and maintenance expenses at generating units and transmission and distribution operating and maintenance expenses and have been separately presented in order to calculate gross margin as defined under GAAP. These amounts exclude general and administrative expenses not directly attributable to revenue-producing activities of $50.6 million and $53.7 million for the three months ended March 31, 2024 and 2023, respectively.

Evergy Kansas Central's gross margin (GAAP) decreased $5.4 million for the three months ended March 31, 2024, compared to the same period in 2023, and Evergy Kansas Central's utility gross margin (non-GAAP) increased $28.9 million for the three months ended March 31, 2024, compared to the same period in 2023, both measures were driven by:

- an $11.0 million decrease due to 2023 mark-to-market gains related to forward contracts for natural gas and electricity entered into as economic hedges against fuel price volatility related to Evergy Kansas Central's 8% ownership share of JEC; partially offset by
- a $39.9 million increase primarily from new Evergy Kansas Central retail rates effective in December 2023.

Additionally, the decrease in Evergy Kansas Central's gross margin (GAAP) was also driven by:

- a $15.0 million increase in depreciation and amortization expense as described further below; and
- an $11.8 million increase in operating and maintenance expenses which are determined to be directly attributable to revenue producing activities primarily driven by a $6.8 million increase in transmission and distribution operating and maintenance expenses and a $2.1 million increase in operating and maintenance expense at Wolf Creek as described further below; and
- a $7.5 million increase in taxes other than income tax as described further below.

Evergy Kansas Central Operating and Maintenance
Evergy Kansas Central's operating and maintenance expense increased $8.7 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $6.8 million increase in transmission and distribution operating and maintenance expenses primarily due to higher labor costs driven by a decrease in labor capitalization and higher employee headcount; and
- a $2.1 million increase in plant operating and maintenance expense at Wolf Creek primarily due to higher material costs.

Evergy Kansas Central Depreciation and Amortization
Evergy Kansas Central's depreciation and amortization expense increased $15.0 million for the three months ended March 31, 2024, compared to the same period in 2023, driven by:

- a $10.1 million increase primarily due to a change in depreciation rates as a result of Evergy Kansas Central's 2023 rate case effective in December 2023; and
- a $4.9 million increase primarily due to capital additions.

Evergy Kansas Central Taxes Other than Income Tax
Evergy Kansas Central's taxes other than income tax increased $7.5 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by the rebasing of property taxes as a result of Evergy Kansas Central's 2023 rate case effective in December 2023.

Evergy Kansas Central Other Income, Net
Evergy Kansas Central's other income, net increased $4.8 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $4.5 million decrease in pension non-service costs primarily due to the resetting of pension expense in retail rates as a result of Evergy Kansas Central's 2023 rate cases effective in December 2023; and
- a $2.7 million increase in equity allowance for funds used during construction (AFUDC) principally driven by lower short-term debt balances in 2024; partially offset by
- a $3.5 million decrease due to recording lower COLI benefits in 2024.

Evergy Kansas Central Interest Expense
Evergy Kansas Central's interest expense increased $3.4 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $4.6 million increase due to the issuance of $400.0 million of 5.70% FMBs in March 2023; and
- a $4.4 million increase due to the issuance of $300.0 million of 5.90% FMBs in November 2023; partially offset by
- a $5.2 million decrease in interest expense on short-term borrowings primarily due to lower short-term debt balances in 2024.

Evergy Kansas Central Income Tax Expense
Evergy Kansas Central's income tax expense decreased $6.3 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by a $5.1 million decrease primarily due to higher wind and other income tax credits in the first quarter of 2024 principally driven by the acquisition of the Persimmon Creek wind farm in 2023.

EVERGY METRO, INC.

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The below results of operations and related discussion for Evergy Metro is presented in a reduced disclosure format in accordance with General Instruction (H)(2)(a) to Form 10-Q.

The following table summarizes Evergy Metro's comparative results of operations.

Three Months Ended March 31	2024	Change	2023
		(millions)	
Operating revenues	$ 420.9	$ 14.5	$ 406.4
Fuel and purchased power	136.6	21.2	115.4
Operating and maintenance	67.9	2.6	65.3
Depreciation and amortization	100.5	(1.9)	102.4
Taxes other than income tax	37.3	3.8	33.5
Income from operations	78.6	(11.2)	89.8
Other expense, net	(1.9)	3.6	(5.5)
Interest expense	37.6	7.0	30.6
Income tax expense	6.4	(0.5)	6.9
Net income	$ 32.7	$ (14.1)	$ 46.8

Evergy Metro Gross Margin (GAAP) and Utility Gross Margin (non-GAAP)

The following table summarizes Evergy Metro's gross margin (GAAP) and MWhs sold and reconciles Evergy Metro's gross margin (GAAP) to Evergy Metro's utility gross margin (non-GAAP). See "Executive Summary - Non-GAAP Measures" for additional information regarding gross margin (GAAP) and utility gross margin (non-GAAP).

	Revenues and Expenses			MWhs Sold		
Three Months Ended March 31	**2024**	**Change**	**2023**	**2024**	**Change**	**2023**
Retail revenues		(millions)			(thousands)	
Residential	$ 156.0	(2.0)	$ 158.0	1,311	(18)	1,329
Commercial	171.2	(4.7)	175.9	1,800	(6)	1,806
Industrial	31.2	2.8	28.4	438	39	399
Other retail revenues	3.2	0.5	2.7	13	(4)	17
Total electric retail	361.6	(3.4)	365.0	3,562	11	3,551
Wholesale revenues	6.3	(5.1)	11.4	743	(83)	826
Transmission revenues	4.9	1.1	3.8	N/A	N/A	N/A
Other revenues	48.1	21.9	26.2	N/A	N/A	N/A
Operating revenues	420.9	14.5	406.4	4,305	(72)	4,377
Fuel and purchased power	(136.6)	(21.2)	(115.4)			
Operating and maintenance [(a)]	(52.3)	(4.7)	(47.6)			
Depreciation and amortization	(100.5)	1.9	(102.4)			
Taxes other than income tax	(37.3)	(3.8)	(33.5)			
Gross margin (GAAP)	**94.2**	**(13.3)**	**107.5**			
Operating and maintenance [(a)]	52.3	4.7	47.6			
Depreciation and amortization	100.5	(1.9)	102.4			
Taxes other than income tax	37.3	3.8	33.5			
Utility gross margin (non-GAAP)	**$ 284.3**	**$ (6.7)**	**$ 291.0**			

[(a)] Operating and maintenance expenses which are deemed to be directly attributable to revenue-producing activities include plant operating and maintenance expenses at generating units and transmission and distribution operating and maintenance expenses and have been separately presented in order to calculate gross margin as defined under GAAP. These amounts exclude general and administrative expenses not directly attributable to revenue-producing activities of $15.6 million and $17.7 million for the three months ended March 31, 2024 and 2023, respectively.

Evergy Metro's gross margin (GAAP) decreased $13.3 million for the three months ended March 31, 2024, compared to the same period in 2023, and Evergy Metro's utility gross margin (non-GAAP) decreased $6.7 million for the three months ended March 31, 2024, compared to the same period in 2023, both measures were driven by:

- a $6.7 million decrease primarily from new Evergy Metro retail rates effective in December 2023.

Additionally, the decrease in Evergy Metro's gross margin (GAAP) was also driven by:

- a $4.7 million increase in operating and maintenance expenses which are determined to be directly attributable to revenue producing activities primarily driven by a $2.8 million increase in transmission and distribution operating and maintenance expense as further described below; and
- a $3.8 million increase in taxes other than income tax as further described below.

Evergy Metro Operating and Maintenance
Evergy Metro's operating and maintenance expense increased $2.6 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $2.8 million increase in transmission and distribution operating and maintenance expenses primarily due to a $1.5 million increase in vegetation management costs and higher labor costs driven by a decrease in labor capitalization and higher employee headcount; and
- a $2.2 million increase in plant operating and maintenance expense at Wolf Creek primarily due to higher material costs; partially offset by
- a $2.3 million decrease due to higher costs billed primarily to Evergy Missouri West for common use assets related to facilities and software assets.

Evergy Metro Taxes Other than Income Tax
Evergy Metro's taxes other than income tax increased $3.8 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by an increase in property taxes primarily driven by higher assessed property valuations.

Evergy Metro Other Expense, Net
Evergy Metro's other expense, net decreased $5.4 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $5.7 million decrease in pension non-service costs primarily due to the resetting of pension expense in retail rates as a result of Evergy Metro's 2023 rate case effective in December 2023; partially offset by
- a $2.3 million decrease in equity AFUDC principally driven by higher short-term debt and lower construction work in progress balances in the first quarter of 2024.

Evergy Metro Interest Expense
Evergy Metro's interest expense increased $7.0 million for the three months ended March 31, 2024, compared to the same period in 2023, primarily driven by:

- a $5.2 million increase in interest expense on short-term borrowings primarily due to higher short-term debt balances in the first quarter of 2024; and
- a $3.7 million increase due to the issuance of $300.0 million of 4.95% Mortgage Bonds in April 2023; partially offset by
- a $2.0 million decrease due to the repayment of $300.0 million of 3.15% Senior Notes at maturity in March 2023.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the ordinary course of business, Evergy faces risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational and credit risks and are discussed elsewhere in this report as well as in the Evergy Companies' combined 2023 Form 10-K and therefore are not represented here.

Evergy's interim period disclosures about market risk included in quarterly reports on Form 10-Q address material changes, if any, from the most recently filed annual report on Form 10-K. Therefore, these interim period disclosures should be read in conjunction with Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk included in the Evergy Companies' combined 2023 Form 10-K. Evergy's exposure to market risk has not changed materially since December 31, 2023.

ITEM 4. CONTROLS AND PROCEDURES

EVERGY

Disclosure Controls and Procedures
Evergy carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of Evergy's management, including the chief executive officer and chief financial officer, and Evergy's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Evergy have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Evergy were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in Evergy's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended March 31, 2024, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

EVERGY KANSAS CENTRAL

Disclosure Controls and Procedures
Evergy Kansas Central carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of Evergy Kansas Central's management, including the chief executive officer and chief financial officer, and Evergy Kansas Central's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Evergy Kansas Central have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Evergy Kansas Central were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in Evergy Kansas Central's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended March 31, 2024, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

EVERGY METRO

Disclosure Controls and Procedures
Evergy Metro carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of Evergy Metro's management, including the chief executive officer and chief financial officer, and Evergy Metro's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Evergy Metro have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Evergy Metro were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in Evergy Metro's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended March 31, 2024, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other Proceedings
The Evergy Companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 4 and 10 to the consolidated financial statements. Such information is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Actual results in future periods for the Evergy Companies could differ materially from historical results and the forward-looking statements contained in this report. The business of the Evergy Companies is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. Additional risks and uncertainties not presently known or that management currently believes to be immaterial may also adversely affect the Evergy Companies. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in Part I, Item 1A, Risk Factors included in the 2023 Form 10-K for each of Evergy, Evergy Kansas Central and Evergy Metro, as well as Quarterly Reports on Form 10-Q and from time to time in Current Reports on Form 8-K filed by Evergy, Evergy Kansas Central and Evergy Metro. There have been no material changes with regard to those risk factors since the filing of the 2023 Form 10-K for each of Evergy, Evergy Kansas Central and Evergy Metro. This information, as well as the other information included in this report and in the other documents filed with the SEC, should be carefully considered before making an investment in the securities of the Evergy Companies. Risk factors of Evergy Kansas Central and Evergy Metro are also risk factors of Evergy.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities

The following table provides information regarding purchases by Evergy of its equity securities that are registered pursuant to Section 12 of the Exchange Act during the three months ended March 31, 2024.

Issuer Purchases of Equity Securities

Month	Total Number of Shares (or Units) Purchased[(a)]	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
January 1 - 31	—	$ —	—	—
February 1 - 29	6,666	50.26	—	—
March 1 - 31	73,729	49.12	—	—
Total	80,395	$ 49.21	—	—

[(a)] Represents shares Evergy purchased for withholding taxes related to the vesting of RSUs.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

Annual Shareholder Meeting Results

Evergy's annual meeting of shareholders was held on May 7, 2024. In accordance with the recommendations of the Board, the shareholders (i) elected eleven directors; (ii) approved, on an advisory and non-binding basis, the 2023 compensation of Evergy's named executive officers; and (iii) ratified the appointment of Deloitte & Touche LLP as independent registered public accountants for 2024. The proposals voted upon at the annual meeting, as well as the voting results for each proposal are set forth below.

Item 1 on the Proxy Card. The eleven persons named below were elected, as proposed in the proxy statement, to serve as directors until Evergy's annual meeting in 2024, and until their successors are elected and qualified. The voting regarding the election was as follows:

	Number of Votes			
	For	Against	Abstain	Broker Non-Votes
David A. Campbell	164,172,532	7,010,769	321,821	24,913,796
B. Anthony Isaac	165,183,915	5,989,728	331,479	24,913,796
Paul M. Keglevic	167,025,646	4,141,419	338,057	24,913,796
Mary L. Landrieu	169,542,450	1,569,147	393,525	24,913,796
Sandra A.J. Lawrence	163,837,341	7,355,892	311,889	24,913,796
Ann D. Murtlow	167,723,063	3,472,369	309,690	24,913,796
Sandra J. Price	165,947,984	5,187,641	369,497	24,913,796
James Scarola	170,255,408	931,138	318,576	24,913,796
Neal A. Sharma	170,460,585	705,993	338,544	24,913,796
C. John Wilder	170,055,323	1,045,026	404,773	24,913,796

Item 2 on the Proxy Card. In an advisory and non-binding "say on pay" vote, shareholders approved the 2023 compensation of Evergy's named executive officers, with the following vote:

Number of Votes			
For	Against	Abstain	Broker Non-Votes
164,378,851	6,461,801	664,470	24,913,796

Item 3 on the Proxy Card. Shareholders voted for the ratification and confirmation of the appointment of Deloitte & Touche LLP as Evergy's independent registered public accounting firm for 2024, with the following vote:

Number of Votes			
For	Against	Abstain	Broker Non-Votes
191,076,557	4,886,019	456,342	0

Available Information

The SEC maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Additionally, information about the Evergy Companies, including their combined annual reports on Form 10-K, combined quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with the SEC, is also available through the Evergy Companies' website, http://investors.evergy.com. Such reports are accessible at no charge and are made available as soon as reasonably practical after such material is filed with or furnished to the SEC.

Investors should note that the Evergy Companies announce material financial information in SEC filings, press releases and public conference calls. In accordance with SEC guidelines, the Evergy Companies also use the

Investor Relations section of their website, http://investors.evergy.com, to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on the Evergy Companies' website is not part of this document.

Securities Trading Plans of Directors and Executive Officers
For the three months ended March 31, 2024, no director or officer has adopted, terminated or modified a Rule 10b5-1 plan or non-Rule 10b5-1 trading arrangement required to be disclosed under Item 408(a) of Regulation S-K.

ITEM 6. EXHIBITS

Exhibit Number		Description of Document	Registrant
4.1	*	Twenty-First Supplemental Indenture, dated as of April 5, 2024, between Evergy Metro and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Evergy's and Evergy Metro's Form 8-K filed on April 5, 2024)	Evergy Evergy Metro
10.1	*	Form of Evergy, Inc. 2024 Time-Based Restricted Stock Unit Agreement (Cliff Vesting) (Exhibit 10.11 to Evergy's Form 10-K for the period ended December 31, 2023)	Evergy Evergy Kansas Central Evergy Metro
10.2	*	Form of Evergy, Inc. 2024 Time-Based Restricted Stock Unit Agreement (Tranche Vesting) (Exhibit 10.12 to Evergy's Form 10-K for the period ended December 31, 2023)	Evergy Evergy Kansas Central Evergy Metro
10.3	*	Form of Evergy, Inc. 2024 Performance-Based Restricted Stock Unit Agreement (Exhibit 10.13 to Evergy's Form 10-K for the period ended December 31, 2023)	Evergy Evergy Kansas Central Evergy Metro
10.4	*	Form of Evergy, Inc. 2024 Annual Incentive Plan (Exhibit 10.14 to Evergy's Form 10-K for the period ended December 31, 2023)	Evergy Evergy Kansas Central Evergy Metro
31.1		Rule 13a-14(a)/15d-14(a) Certification of David A. Campbell.	Evergy
31.2		Rule 13a-14(a)/15d-14(a) Certification of Kirkland B. Andrews.	Evergy
31.3		Rule 13a-14(a)/15d-14(a) Certification of David A. Campbell.	Evergy Metro
31.4		Rule 13a-14(a)/15d-14(a) Certification of Kirkland B. Andrews.	Evergy Metro
31.5		Rule 13a-14(a)/15d-14(a) Certification of David A. Campbell.	Evergy Kansas Central
31.6		Rule 13a-14(a)/15d-14(a) Certification of Kirkland B. Andrews.	Evergy Kansas Central
32.1	**	Section 1350 Certifications.	Evergy
32.2	**	Section 1350 Certifications.	Evergy Metro
32.3	**	Section 1350 Certifications.	Evergy Kansas Central
101.INS	***	XBRL Instance Document.	n/a
101.SCH		Inline XBRL Taxonomy Extension Schema Document.	Evergy Evergy Kansas Central Evergy Metro
101.CAL		Inline XBRL Taxonomy Extension Calculation Linkbase Document.	Evergy Evergy Kansas Central Evergy Metro
101.DEF		Inline XBRL Taxonomy Extension Definition Linkbase Document.	Evergy Evergy Kansas Central Evergy Metro
101.LAB		Inline XBRL Taxonomy Extension Labels Linkbase Document.	Evergy Evergy Kansas Central Evergy Metro
101.PRE		Inline XBRL Taxonomy Extension Presentation Linkbase Document.	Evergy Evergy Kansas Central Evergy Metro

104	Cover Page Interactive Data File (embedded within the Inline XBRL document).	Evergy Evergy Kansas Central Evergy Metro

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

** Furnished and shall not be deemed filed for the purpose of Section 18 of the Exchange Act. Such document shall not be incorporated by reference into any registration statement or other document pursuant to the Exchange Act or the Securities Act of 1933, as amended, unless otherwise indicated in such registration statement or other document.

*** The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from Evergy, Evergy Kansas Central or Evergy Metro, as applicable, upon written request.

The registrants agree to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of such registrant and its subsidiaries on a consolidated basis.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, Evergy, Inc., Evergy Kansas Central, Inc. and Evergy Metro, Inc. have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

	EVERGY, INC.
Dated: May 8, 2024	By: /s/ Kirkland B. Andrews (Kirkland B. Andrews) (Executive Vice President and Chief Financial Officer)
	EVERGY KANSAS CENTRAL, INC.
Dated: May 8, 2024	By: /s/ Kirkland B. Andrews (Kirkland B. Andrews) (Executive Vice President and Chief Financial Officer)
	EVERGY METRO, INC.
Dated: May 8, 2024	By: /s/ Kirkland B. Andrews (Kirkland B. Andrews) (Executive Vice President and Chief Financial Officer)

Exhibit 31.1

CERTIFICATIONS

I, David A. Campbell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Evergy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2024

/s/ David Campbell
David A. Campbell
Chairman, Chief Executive Officer and President

Exhibit 31.2

CERTIFICATIONS

I, Kirkland B. Andrews, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Evergy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2024

/s/ Kirkland B. Andrews
Kirkland B. Andrews
Executive Vice President and
Chief Financial Officer

Exhibit 31.3

CERTIFICATIONS

I, David A. Campbell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Evergy Metro, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2024

/s/ David Campbell
David A. Campbell
Chairman, Chief Executive Officer and President

Exhibit 31.4

CERTIFICATIONS

I, Kirkland B. Andrews, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Evergy Metro, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2024

/s/ Kirkland B. Andrews
Kirkland B. Andrews
Executive Vice President and
Chief Financial Officer

Exhibit 31.5

CERTIFICATIONS

I, David A. Campbell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Evergy Kansas Central, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2024

/s/ David Campbell
David A. Campbell
Chairman, Chief Executive Officer and President

Exhibit 31.6

CERTIFICATIONS

I, Kirkland B. Andrews, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Evergy Kansas Central, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2024

/s/ Kirkland B. Andrews
Kirkland B. Andrews
Executive Vice President and
Chief Financial Officer

Exhibit 32.1

Certification of CEO and CFO Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report on Form 10-Q of Evergy, Inc. (the "Company") for the quarterly period ended March 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), David A. Campbell, as President and Chief Executive Officer of the Company, and Kirkland B. Andrews, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ David Campbell
Name:	David A. Campbell
Title:	Chairman, Chief Executive Officer and President
Date:	May 8, 2024

	/s/ Kirkland B. Andrews
Name:	Kirkland B. Andrews
Title:	Executive Vice President and Chief Financial Officer
Date:	May 8, 2024

Exhibit 32.2

Certification of CEO and CFO Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report on Form 10-Q of Evergy Metro, Inc. (the "Company") for the quarterly period ended March 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), David A. Campbell, as President and Chief Executive Officer of the Company, and Kirkland B. Andrews, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ David Campbell
Name:	David A. Campbell
Title:	Chairman, Chief Executive Officer and President
Date:	May 8, 2024

	/s/ Kirkland B. Andrews
Name:	Kirkland B. Andrews
Title:	Executive Vice President and Chief Financial Officer
Date:	May 8, 2024

Exhibit 32.3

Certification of CEO and CFO Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report on Form 10-Q of Evergy Kansas Central, Inc. (the "Company") for the quarterly period ended March 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), David A. Campbell, as President and Chief Executive Officer of the Company, and Kirkland B. Andrews, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ David Campbell
Name:	David A. Campbell
Title:	Chairman, Chief Executive Officer and President
Date:	May 8, 2024
	/s/ Kirkland B. Andrews
Name:	Kirkland B. Andrews
Title:	Executive Vice President and Chief Financial Officer
Date:	May 8, 2024

REDACTED

CONFIDENTIAL

APPENDIX 9

Credit REPORT – Evergy, Inc.

and

Credit REPORT – American Electric Power Company, Inc.