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) Public Service Company of Oklahoma	Year/Period of Report End of: 2023/ Q4

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 Public Service Company of Oklahoma	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, Columbus, Ohio 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) AEP Service Corporation, 1 Riverside Plaza, Columbus, Ohio 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: Public Service Company of Oklahoma	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)
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	NA
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	NA
50	**Transmission of Electricity by Others**	332	
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	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	NA
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	NA
66.2	**Energy Storage Operations (Small Plants)**	419	NA
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
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		

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Name of Respondent: Public Service Company of Oklahoma	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

212 East 6th StreetTulsa, Oklahoma 74119

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.

OklahomaMay 29, 1913

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.

The generation, transmission and sale of electric energy.All operations within the State of Oklahoma.

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: Public Service Company of Oklahoma	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.

American Electric Power Company, Inc., a registered holding company, owns 100% of the Respondent's outstanding shares of Common Stock.

Name of Respondent: Public Service Company of Oklahoma	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)
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Name of Respondent: Public Service Company of Oklahoma	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	[(a)] Footnote				

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Name of Respondent: Public Service Company of Oklahoma	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: OfficerTitle

Summary Compensation Table

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our two Chief Financial Officers during 2023, the three other most highly compensated executive officers and one additional former executive officer whose compensation would have been among the three most highly compensated executive officers other than the CEO and CFOs if he had been an executive officer at year end. We refer collectively to this group as the named executive officers (NEOs) .

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5)	All Other Compensation ($)(6)	Total ($)
Julia A. Sloat								
Chair of the Board, President and Chief Executive Officer	2023	1,200,000	—	8,321,524	787,503	210,263	114,555	10,633,745
Charles E. Zebula								
Executive Vice President and Chief Financial Officer	2023	639,625	—	2,852,248	240,500	181,438	73,170	3,986,981
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2023	746,000	— —	1,560,286	263,500	151,597	109,767	2,831,150
Christian T. Beam								
Executive Vice President - Energy Services	2023	585,000	—	1,248,229	220,500	123,014	170,900	2,347,643
Peggy I. Simmons								
Executive Vice President - Utilities	2023	585,000	—	1,248,229	220,500	86,652	87,482	2,227,863
Nicholas K. Akins								
Former Executive Chair of the Board	2023	862,500	—	2,000,000	696,149	729,068	359,384	4,647,101
Ann P. Kelly								
Former Executive Vice President and Chief Financial Officer	2023	525,000	250,000	2,042,588	—	—	550,866	3,368,454

1. Amounts in the salary column are composed of executive salaries earned for the year shown, which include 260 days of pay for 2023, which is the number of workdays and holidays in a standard year.
2. The amount in the bonus column for Ms. Kelly is a negotiated hire bonus paid in 2023 following her November 2022 hire into the EVP and CFO position.
3. The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance shares, restricted stock units (RSUs) and unrestricted shares granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2023 for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of the performance shares, if any, will depend on the Company's performance during a 3-year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance shares, plus any dividend equivalents. The value of the performance shares will be based on three measures: a Board approved cumulative operating earnings per share
measure (Cumulative EPS 50%), a total shareholder return relative to peer companies (Relative TSR 40%) and a carbon free generation capacity additions (Carbon Free Additions 10%). The grant date fair value of the 2023, 2022 and 2021 performance shares that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the grant date. The maximum amount payable for the 2023 performance shares that are based on Cumulative EPS measured on the grant date is $3,000,000 for Ms. Sloat, $487,500 for Mr. Zebula, 562,500 for Mr. Feinberg, $450,000 for Mr. Beam, $450,000 for Ms. Simmons, $0 for Mr. Akins, and $652,495 for Ms. Kelly. The maximum amount payable for the 2023 performance shares that are based on Carbon Free Capacity additions is $600,000 for Ms. Sloat, $97,500 for Mr. Zebula, $112,500 for Mr. Feinberg, $90,000 for Mr. Beam, $90,000 for Ms. Simmons, $0 Mr. Akins, and $130,499 for Ms. Kelly. The grant date fair value of the 2023 performance shares that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Topic 718. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value. The values realized from the 2021 performance shares are included in the Option Exercises and Stock Vested for 2023 table.
4. The amounts shown in this column reflect annual incentive compensation paid for the year shown.
5. The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit pension plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2023 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.
6. Amounts shown in the All Other Compensation column for 2023 include: (a) Company matching contributions to the Company's Retirement Savings Plan, (b) Company matching contributions to the Company's Supplemental Retirement Savings Plan, (c) relocation, (d) perquisites, and (e) vacation payout. The 2023 values for these items are listed in the following table:

Type	Julia A. Sloat	Charles E. Zebula	David M. Feinberg	Christian T. Beam	Peggy I. Simmons	Nicholas K. Akins	Ann P. Kelly
Retirement Savings Plan Match	$ 14,850	$ 14,850	$ 14,850	$ 14,85	$ 14,850	$ 14,850	$ 14,850
Supplemental Retirement Savings Plan Match	84,297	45,565	54,917	30,349	22,275	188,169	7,043
Relocation	—	—	—	111,156	35,812	—	238,006
Perquisites	15,308	12,755	40,000	14,545	14,545	20,632	264,717
Vacation Payout	—	—	—	—	—	135,733	26,250
Total	**$ 114,455**	**$ 73,170**	**$ 109,767**	**$ 170,900**	**$ 87,482**	**$ 359,384**	**$ 550,866**

Perquisites provided in 2023 included: financial counseling and tax preparation services and, for Ms. Sloat and Mr. Akins, director's group travel accident insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time-to-time executive officers may receive customary gifts from third parties that sponsor events (subject to our policies on conflicts of interest).

Provided Ms. Kelly complies with the terms of her Executive Severance, Noncompetition and Release of All Claims Agreement, she will receive $1,260,000 in cash severance benefits and up to $15,650 in outplacement services in 2024 in connection with her 2023 separation from AEP employment.

Name of Respondent: Public Service Company of Oklahoma	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	Paul Chodak, Vice President	Columbus. Ohio		
2	David M. Feinberg, Secretary and Vice President	Columbus. Ohio		
3	Ann P. Kelly, Chief Financial Officer and Vice President	Columbus. Ohio		
4	Therace M. Risch, Vice President	Columbus. Ohio		
5	Julia A.Sloat, Chair of the Board and Chief Executive Officer	Columbus, Ohio		
6	Leigh Anne, Strahler, President and Chief Operating Officer	Columbus, Ohio		
7	Toby L. Thomas, Vice President	Columbus, Ohio		
8	Phillip R. Ulrich, Vice President	Columbus, Ohio		
9	Christian T. Beam, Vice President	Columbus, Ohio		
10	Peggy I. Simmons, Vice President	Columbus, Ohio		
11	Rajagopalan, Sundararajan, Executive Vice President	Columbus, Ohio		
12	Antonio P. Smyth, Vice President	Columbus, Ohio		
13	The Respondent does not have an Executive Committee.			

Name of Respondent: Public Service Company of Oklahoma	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	SPP FERC Electric Tariff 6th Revision Vol. No. 1	ER07-1069
2	Addendum 4 to Attachment H, Parts 1 and 2	
3	SPP FERC Electric Tariff Vol. No. 1	ER18-195
4	Attachment H, Parts 1 and 2	
5	Rate Schedule 233	ER89-476
6		ER92-191

Name of Respondent: Public Service Company of Oklahoma	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 (Checked by default - Not explicitly defined)

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	20090526-5302	05/26/2009	ER09-1198-000	AEP SPP 2009 Trans FR Update	SPP OATT Att. H-4
2	20090831-5276	08/31/2009	ER09-1198-000	Errata of 2009 Update	SPP OATT Att. H-4
3	20100525-5109	05/25/2010	ER10-355-000	AEP SPP 2010 Trans FR Update	SPP OATT Att. H-4
4	20110928-5123	09/28/2011	ER11-4671-000	AEP SPP 2011 Trans FR Update	SPP OATT Att. H-4
5	20111221-5253	12/21/2011	ER11-1069-000	Errata of 2011 Update	SPP OATT Att. H-4
6	20120523-5024	05/23/2012	ER07-1069-000	AEP SPP 2012 Trans FR Update	SPP OATT Att. H-4
7	20130910-3004	05/24/2013	ER13-1606-000	AEP SPP 2013 Trans FR Update	SPP OATT Att. H-4
8	20141208-5379	12/08/2014	ER07-1069-000	AEP SPP 2014 Trans FR Update	SPP OATT Att. H-4
9	20150604-5186	05/14/2015	ER07-1069-000	AEP SPP 2015 Trans FR Update	SPP OATT Att. H-4
10	20160523-5233	05/23/2016	ER07-1069-000	AEP SPP 2016 Trans FR Update	SPP OATT Att. H-4
11	20160630-5407	06/30/2016	ER07-1069-000	Errata of 2016 Update	SPP OATT Att. H-4
12	20170525-5337	05/25/2017	ER07-1069-000	AEP SPP 2017 Trans FR Update	SPP OATT Att. H-4
13	20171031-5311	10/31/2017	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
14	20180525-5243	05/25/2018	ER18-195-000	AEP SPP 2018 Trans FR Update	SPP OATT Att. H-4
15	20181101-5217	11/01/2018	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
16	20181213-5182	12/13/2018	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
17	20190528-5199	05/28/2019	ER18-195-000	AEP SPP 2019 Trans FR Update	SPP OATT Att. H-4
18	20190723-5114	07/23/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
19	20190724-5030	07/24/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
20	20190731-5132	07/31/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
21	20191031-5138	10/31/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
22	20200526-5243	05/26/2020	ER18-195-000	AEP SPP 2020 Trans FR Update	SPP OATT Att. H-4
23	02200609-5107	06/09/2020	ER18-195-000	AEP SPP 2020 Trans FR Update	SPP OATT Att. H-4
24	20201102-5246	11/02/2020	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
25	20210525-5227	05/25/2021	ER18-195-000	AEP SPP 2021 Trans FR Update	SPP OATT Att. H-4

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)
26	20211101-5258	11/01/2021	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
27	20220525-5165	05/25/2022	ER18-195-000	AEP SPP 2022 Trans FR Update	SPP OATT Att. H-4
28	20220602-5172	06/02/2022	ER18-195-000	AEP SPP 2022 Trans FR Update	SPP OATT Att. H-4
29	20221101-5102	11/01/2022	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
30	20230525-5144	05/25/2023	ER18-195-000	AEP SPP 2023 Trans FR Update	SPP OATT Att. H-4
31	20231031-5363	10/31/2023	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
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Name of Respondent: Public Service Company of Oklahoma	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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Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
41				
42				
43				
44				
Page 106b				

Name of Respondent: Public Service Company of Oklahoma	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 ratio.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1

By Company-Community [full name of village, township or city, county and include state]	Renewal Date/Auto Renewal [state date or auto]	Consideration [state dollar amount or state none]
City of Grove, Delaware County OK	1/20/2048	no financial contribution (2% franchise fee)
Town of Adair, Mayes County OK	1/18/2048	no financial contribution
Town of Oologah, Rogers County OK	1/18/2048	no financial contribution
Town of Allen, Pontotoc and Hughes Counties, OK	2/27/2048	no financial contribution
City of Minco, Grady County OK	2/28/2048	no financial contribution
Town of Butler, Custer County, OK	2/28/2048	no financial contribution
City of Broken Arrow, Tulsa & Wagoner Counties, OK	2/21/2048	no financial contribution (2% franchise fee)
Bridgeport, Caddo County, OK	3/28/2048	no financial contribution
Ninnekah, Grady County, Oklahoma	3/23/2048	633
Porter, Wagoner County, OK	4/17/2048	none
Bartlesville, Washington County, OK	5/17/2048	no financial contribution
Weatherford, Custer County, OK	5/19/2048	$11,647.20 spent on campaign advertising
Keota, Haskell County, OK	5/9/2048	none
Carnegie, Caddo County, OK	8/28/2048	none
Catoosa, Rogers County, OK	8/18/2048	none
Kinta, Haskell Co., OK	7/11/2048	none
Bromide, Johnston County, OK	10/10/2048	none
Atoka, Atoka County, OK	11/27/2048	none
Sportsmen Acres, Mayes, County, OK	11/16/2048	none
Schulter, Okmulgee County, OK	11/9/2048	none

2. None

3. None

4. None

5. None

6. Public Service Company of Oklahoma Senior Unsecured Note, Series L $475M; State Authority: 717743; FERC Authority: N/A; Issued: 01/05/2023; Maturity: 01/15/2033

7. None

8. 560 PSO employees represented by IBEW #1002 were provided with a 2.5% contract and wages effective 10/1/23

9. None

10. None

12. Not Used
13. Julia A .Sloat elected as Chair of the Board and Chief Executive Officer effective on 1/1/2023 Antonio P. Smyth elected as Director effective on 04-12-2023 Dana M. Koenig elected as Assistant Vice President - Tax effective on 04-11-2023 Kate Sturgess elected as Chief Accounting Officer effective on 05-09-2023 Kate Sturgess elected as Controller effective on 05-09-2023 Joseph M. Buonaiuto resigned as Chief Accounting Officer effective on 05-08-2023 Joseph M. Buonaiuto resigned as Controller effective on 05-08-2023 Rajagopalan, Sundararajan resigned as Director effective on 04-05-2023 Peggy I. Simmons elected as Vice President effective on 08-18-2023 Christian T. Beam elected as Vice President effective on 08-18-2023 Daniel E. Mueller elected as Assistant Vice President - Tax effective on 09-28-2023 Paul III. Chodak resigned as Director effective on 07-26-2023 Paul III. Chodak resigned as Vice President effective on 08-18-2023 Eric J. James resigned as Vice President effective on 08-18-2023 Ann P Kelly resigned as Vice President, Chief Financial Officer & Director effective on 09-29-2023 Mark J. Leskowitz resigned as President effective on 08-18-2023 Scott P. Moore resigned as Vice President effective on 08-18-2023 Daniel E. Mueller resigned as Assistant Vice President - Tax effective on 08-18-2023 Thomas D. Presthus resigned as Vice President effective on 08-18-2023 Therace M. Risch resigned as Vice President effective on 08-18-2023 Scott N. Smith, resigned as Vice President effective on 07-14-2023 Toby L. Thomas, resigned as Vice President effective on 08-18-2023 Toby L. Thomas, resigned as Director effective on 07-26-2023 Phillip R. Ulrich, resigned as Vice President effective on 08-18-2023 Charles E. Zebula, resigned as Vice President effective on 08-18-2023 Charles E Zebula, elected as Vice President, Chief Financial Officer & Director effective on 10-03-2023
14. Proprietary capital ratio exceeds 30%

Name of Respondent: Public Service Company of Oklahoma	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	7,984,575,442	7,339,541,669
3	Construction Work in Progress (107)	200	319,053,347	222,650,070
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		8,303,628,789	7,562,191,739
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,225,710,913	1,999,685,062
6	Net Utility Plant (Enter Total of line 4 less 5)		6,077,917,876	5,562,506,678
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)		6,077,917,876	5,562,506,678
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,241,507	3,241,507
19	(Less) Accum. Prov. for Depr. and Amort. (122)		(1,731,875)	(1,767,598)
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		21	21
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)		68,400,234	67,328,614
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)		73,373,637	72,337,740
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		2,483,765	4,013,379
36	Special Deposits (132-134)		948,735	13,127,200
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		106,530,262	68,982,944
41	Other Accounts Receivable (143)		788,149	756,732
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		59,465	(15,821)
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		28,346,850	49,105,381
45	Fuel Stock (151)	227	31,456,037	10,868,527

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)
46	Fuel Stock Expenses Undistributed (152)	227	2,219,109	730,099
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	106,836,028	109,826,969
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	41,584	1,262,825
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)		8,675,932	6,313,500
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		1,089,467	1,080,480
61	Accrued Utility Revenues (173)		28,687,104	34,382,884
62	Miscellaneous Current and Accrued Assets (174)		8,224,430	1,988,610
63	Derivative Instrument Assets (175)		18,977,961	23,678,914
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			1,612,498
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		345,245,947	327,746,764
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,644,926	10,980,453
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	490,289,394	694,526,532
73	Prelim. Survey and Investigation Charges (Electric) (183)		8,180,255	7,439,908
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			4,502
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	33,498,857	11,336,987
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		4,784,795	5,220,922
82	Accumulated Deferred Income Taxes (190)	234	282,366,473	224,960,284
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		831,764,700	954,469,588
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,328,302,160	6,917,060,769
	Page 110-111			

Name of Respondent: Public Service Company of Oklahoma	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	157,230,000	157,230,000
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	1,039,285,544	1,042,627,545
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	1,374,328,564	1,217,976,436
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)	(231,816)	1,273,874
16	Total Proprietary Capital (lines 2 through 15)		2,570,612,292	2,419,107,855
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	2,401,982,564	1,927,525,458
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,751,940	3,677,473
24	Total Long-Term Debt (lines 18 through 23)		2,397,230,624	1,923,847,985
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		117,438,397	111,036,540
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		99,084	90,798
29	Accumulated Provision for Pensions and Benefits (228.3)		3,162,853	4,601,040
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		5,512,769	1,669,865
32	Long-Term Portion of Derivative Instrument Liabilities		1,000,451	
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		84,177,536	75,664,252
35	Total Other Noncurrent Liabilities (lines 26 through 34)		211,391,090	193,062,495
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		159,299,634	202,896,330
39	Notes Payable to Associated Companies (233)		54,421,420	364,212,319
40	Accounts Payable to Associated Companies (234)		85,359,292	111,061,354
41	Customer Deposits (235)		81,350,030	59,014,263
42	Taxes Accrued (236)	262	(321,723)	12,648,206
43	Interest Accrued (237)		30,732,340	18,242,220
44	Dividends Declared (238)			

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)
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		8,810,009	8,789,343
48	Miscellaneous Current and Accrued Liabilities (242)		82,214,889	53,955,434
49	Obligations Under Capital Leases-Current (243)		13,207,640	12,094,366
50	Derivative Instrument Liabilities (244)		29,891,055	1,555,822
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,000,451	
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)		543,964,135	844,469,657
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	47,186,819	48,171,303
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	25,070,635	16,930,465
60	Other Regulatory Liabilities (254)	278	419,221,976	457,899,623
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	14,794,530	15,366,719
63	Accum. Deferred Income Taxes-Other Property (282)		846,683,770	761,542,229
64	Accum. Deferred Income Taxes-Other (283)		252,146,288	236,662,442
65	Total Deferred Credits (lines 56 through 64)		1,605,104,018	1,536,572,781
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,328,302,160	6,917,060,773
	Page 112-113			

Name of Respondent: Public Service Company of Oklahoma	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	1,990,013,972	1,892,057,867			1,990,013,972					
3	Operating Expenses											
4	Operation Expenses (401)	320	1,294,430,922	1,274,152,187			1,294,430,922					
5	Maintenance Expenses (402)	320	112,180,880	114,537,436			112,180,880					
6	Depreciation Expense (403)	336	219,100,561	207,355,298			219,100,561					
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	1,632,857	1,329,494			1,632,857					
8	Amort. & Depl. of Utility Plant (404-405)	336	19,963,799	17,661,444			19,963,799					
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)		9,063,987	9,243,872			9,063,987					
13	(Less) Regulatory Credits (407.4)		(6,118,565)	5,329,568			(6,118,565)					

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)
14	Taxes Other Than Income Taxes (408.1)	262	64,152,333	57,574,758			64,152,333					
15	Income Taxes - Federal (409.1)	262	(64,100,713)	(641,758)			(64,100,713)					
16	Income Taxes - Other (409.1)	262	(1,007,018)	230,439			(1,007,018)					
17	Provision for Deferred Income Taxes (410.1)	234, 272	274,413,810	501,612,259			274,413,810					
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	266,856,452	561,229,826			266,856,452					
19	Investment Tax Credit Adj. - Net (411.4)	266	(984,485)	13,516,472			(984,485)					
20	(Less) Gains from Disp. of Utility Plant (411.6)		798,047				798,047					
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		22				22					
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		4,734,431	4,059,699			4,734,431					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,672,045,409	1,634,072,207			1,672,045,408					
27	Net Util Oper Inc (Enter Tot line 2 less 25)		317,968,563	257,985,660			317,968,564					
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)		3,487	2,360								
33	Revenues From Nonutility Operations (417)		806,869	676,849								
34	(Less) Expenses of Nonutility Operations (417.1)		35,723	35,787								
35	Nonoperating Rental Income (418)		49,009	128,549								

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)
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		1,810,252	7,432,649								
38	Allowance for Other Funds Used During Construction (419.1)		8,363,751	1,513,241								
39	Miscellaneous Nonoperating Income (421)		316,182	133,612								
40	Gain on Disposition of Property (421.1)			69,714								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		11,306,854	9,916,468								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		2,032	233,525								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		293,856	6,213,969								
46	Life Insurance (426.2)											
47	Penalties (426.3)		12,732	530								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		565,268	716,908								
49	Other Deductions (426.5)		11,433,815	12,294,825								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,307,703	19,459,757								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262										
53	Income Taxes-Federal (409.2)	262	3,284,706	(2,703,007)								
54	Income Taxes-Other (409.2)	262	1,280,793	(248,871)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	2,004,597	997,043								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	1,617,486	777,093								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											

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)
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		4,952,611	(2,731,928)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(5,953,460)	(6,811,361)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		100,099,953	76,522,658								
63	Amort. of Debt Disc. and Expense (428)		1,743,301	1,049,759								
64	Amortization of Loss on Reaquired Debt (428.1)		436,127	436,127								
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)		2,278,948	5,464,663								
68	Other Interest Expense (431)		3,802,075	2,841,680								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,197,429	2,744,980								
70	Net Interest Charges (Total of lines 62 thru 69)		103,162,974	83,569,906								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		208,852,129	167,604,392								
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	0									
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		208,852,129	167,604,392								

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Name of Respondent: Public Service Company of Oklahoma	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		1,217,976,436	1,095,372,043
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			
10.1	Adj to Retained Earnings			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		208,852,128	167,604,393
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)			
30.1	$15 par value 9,013,000 shares outstanding			
30.2	Total Dividends Decl - Common Stk (438)		(52,500,000)	(45,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(52,500,000)	(45,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,374,328,564	1,217,976,436
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)		1,374,328,564	1,217,976,436
	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: Public Service Company of Oklahoma	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)	208,852,129	167,604,392
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	240,697,217	226,346,236
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	15,182,552	3,914,304
8	Deferred Income Taxes (Net)	7,944,470	(59,397,616)
9	Investment Tax Credit Adjustment (Net)	(984,485)	13,516,472
10	Net (Increase) Decrease in Receivables	(16,753,904)	(44,992,423)
11	Net (Increase) Decrease in Inventory	(18,039,923)	(49,851,628)
12	Net (Increase) Decrease in Allowances Inventory	1,221,242	(1,260,027)
13	Net Increase (Decrease) in Payables and Accrued Expenses	(64,336,093)	70,417,305
14	Net (Increase) Decrease in Other Regulatory Assets	201,871,768	447,168,892
15	Net Increase (Decrease) in Other Regulatory Liabilities	(9,263,423)	8,920,245
16	(Less) Allowance for Other Funds Used During Construction	8,363,751	1,513,241
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	[(a)] Other (provide details in footnote):	12,948,755	(35,875,178)
18.2	Customer Deposits	22,335,766	2,858,713
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	593,312,320	747,856,446
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(576,821,250)	(451,776,063)
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	(8,363,751)	(1,513,241)
31	Other (provide details in footnote):		
31.1	Acquired Assets	(146,369,254)	(549,766,394)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(714,826,753)	(1,000,029,216)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(b)] 4,475,368	2,564,115
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)		

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)
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		
53	Other (provide details in footnote):		
53.1	Proceeds from Disposal of Noncurrent Assets-Fixed Assets		
53.2	Insurance Receivable	9,057,206	
53.3	Contribution In Aid of Construction Proceeds	2,380,853	2,189,148
53.4	(Increase) Decrease in Other Special Deposits	(21,836)	6,345
53.5	Notes Receivable from Associated Companies		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(698,935,162)	(995,269,609)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	475,000,000	500,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Long Term Issuances Costs	(5,167,406)	(331,314)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds on Capital Leaseback	436,426	453,343
67.2	Notes Payable to Associated Companies - Issued		291,940,328
67.3	Capital Contributions from Parent	(3,342,000)	3,626,217
70	Cash Provided by Outside Sources (Total 61 thru 69)	466,927,020	795,688,574
72	Payments for Retirement of:		
73	Long-term Debt (b)	(542,894)	(500,526,870)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired	(309,790,898)	
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(52,500,000)	(45,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	104,093,228	250,161,704
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)	(1,529,614)	2,748,541
88	Cash and Cash Equivalents at Beginning of Period	4,013,379	1,264,838
90	Cash and Cash Equivalents at End of Period	2,483,765	4,013,379
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Name of Respondent: Public Service Company of Oklahoma	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: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (42,224,374)	$ (33,038,548)
Property and Investments, Net	35,723	284,703
Margin Deposits	12,200,300	(6,233,498)
Mark-to-Market of Risk Management Contracts	33,036,185	(13,660,352)
Prepayments	(10,904,410)	(5,299,830)
Accrued Utility Revenues, Net	5,695,780	(8,959,354)
Miscellaneous Current and Accr Assets	1,279,675	—
Unamortized Debt Expense	2,044,022	(35,454)
Other Deferred Debits, Net	(22,236,554)	(10,074,563)
Other Comprehensive Income, Net	(231,816)	—
Unamortized Discount/Premium on Long-Term Debt	398,033	250,783
Accumulated Provisions - Misc	2,014,510	1,980,724
Current and Accrued Liabilities, Net	20,015,407	27,958,168
Other Deferred Credits, Net	11,826,276	10,952,041
Total	**$ 12,948,757**	**$ (35,875,180)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Land Sale 24.94 +/- acres in Seminole County	$ —	$ 100,000
Sales of Meters	52,136	29,155
Sale of Transformers	1,727,555	669,781
Transfer of Assets	2,695,677	1,765,179
Total	**$ 4,475,368**	**$ 2,564,115**

Name of Respondent: Public Service Company of Oklahoma	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 Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
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.
AFUDC	Allowance for Equity Funds Used During Construction.
APCo	Appalachian Power Company, an AEP electric utility subsidiary. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
ARO	Asset Retirement Obligations.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
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.
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.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
Maverick	Maverick, part of the North Central Wind Energy Facilities, consists of 287 MWs of wind generation in Oklahoma.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
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.
NOLC	Net operating losses carryforwards.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.

Term	Meaning
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SPP	Southwest Power Pool regional transmission organization.
Sundance	Sundance, acquired in April 2021 as part of the North Central Wind Energy Facilities, consists of 199 MWs of wind generation in Oklahoma.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary. SWEPCo engages in the generation, transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
Traverse	Traverse, part of the North Central Wind Energy Facilities, consists of 998 MWs of wind generation in Oklahoma.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 578,000 retail customers in its service territory in eastern and southwestern Oklahoma. PSO sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

The OCC regulates all of the retail distribution operations and rates of PSO's retail public utility subsidiaries on a cost basis. The OCC also regulates the retail generation/power supply operations and rates.

The FERC also regulates PSO's wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Bundled retail transmission rates are regulated, on a cost basis, by the OCC.

In addition, the FERC regulates the Operating Agreement and TCA, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. See Note 15 - Related Party Transactions for additional information.

Basis of Accounting

PSO's accounting is subject to the requirements of the OCC and the FERC. 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 classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of SPP purchases as operation expenses instead of a reduction in revenue.
- 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 presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- 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 classification of gas procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of accrued unbilled revenue as a current and accrued asset rather than netted against accounts payable for affiliated companies.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of unrecovered plant costs as accumulated depreciation instead of regulatory assets.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.

Accounting for the Effects of Cost-Based Regulation

PSO'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. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

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

Cash and Cash Equivalents

Cash and Cash Equivalents include 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 millions)**	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 87.0	$ 79.4
Income Taxes (Net of Refunds)	(10.6)	(12.5)
Sale of Transferable Tax Credits	(34.6)	—
Noncash Acquisitions Under Finance Leases	2.1	2.8
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	72.9	69.8

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Uncollectible Accounts

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

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

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with PSO. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for a portion of its interests in the billed and unbilled receivables acquired from the affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 14 for additional information.

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from PSO. The assessment is performed separately for PSO, which inherently contemplates any differences in geographical risk characteristics for the allowance for uncollectible accounts.

For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

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

Concentrations of Credit Risk and Significant Customers

PSO does not have any significant customers that comprise 10% or more of its operating revenues for the years ended December 31, 2023 and 2022.

PSO monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The OCC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying financial statements.

Renewable Energy Credits

PSO records renewable energy credits (RECs) at cost. PSO follows the inventory model for these RECs. RECs are reported in Miscellaneous Current and Accrued Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Operation Expenses at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs.

Property, Plant and Equipment

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

Removal costs accrued are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are 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 or is not probable, the cost of that asset shall be written down to its then current estimated fair value, with the change charged to expense, and the asset is removed from plant-in-service or CWIP. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Asset Retirement Obligations

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

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, Notes Receivable from Associated Companies, Notes Payable to Associated Companies, 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.

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

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

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

Deferred Fuel Costs

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the OCC. On a routine basis, the OCC reviews and/or audits PSO's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. PSO shares the majority of its Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, on-existent or not applicable to merchant operations, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

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

Retail and Wholesale Supply and Delivery of Electricity

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

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by PSO in the fourth quarter of each calendar year and a final annual true-up is recognized by PSO in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets. See Note 17 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to SPP. PSO also purchases power from SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to SPP, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses on the statements of income.

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

In general, PSO records expenses when purchased electricity is received and when expenses are incurred. PSO defers unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

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

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

PSO uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. Unrealized MTM gains and losses are included on the balance sheets as Derivative Instrument Assets or Liabilities, as appropriate, and on the statements of income in Operating Revenues. PSO includes realized gains and losses on marketing
and risk management transactions in revenue or expense based on the transaction's facts and circumstances. The unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

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

Maintenance

PSO expenses maintenance costs as incurred. If it becomes probable that PSO will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with its recovery in cost-based regulated revenues. PSO defers costs above the level included in base rates and amortizes those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment and Production Tax Credits

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

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

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

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

PSO accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." PSO classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income.

Excise Taxes

As an agent for some state and local governments, PSO collects from customers certain excise taxes levied by those state or local governments on customers. PSO does not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to
the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

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

Pension and OPEB Plans

PSO participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all PSO employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. PSO also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees. PSO is allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

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

Benefit Plans

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Comprehensive Income (Loss)

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

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2022 through February 26, 2024, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 9, 2024. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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

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

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

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

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

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.
The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

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

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

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

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

3. <u>COMPREHENSIVE INCOME</u>

PSO's balance and activity in AOCI was not material for the years ended December 31, 2023 and 2022.

4. <u>RATE MATTERS</u>

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

2022 Oklahoma Base Rate Case

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

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

2024 Oklahoma Base Rate Case

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

FERC 2019 SPP Transmission Formula Rate Challenge

In May 2021, certain joint customers submitted a formal challenge at the FERC related to the 2020 Annual Update of the 2019 SPP Transmission Formula Rates of the AEP transmission owning subsidiaries within SPP, including PSO. In March 2022, the FERC issued an order granting the formal challenge on several issues and denying the formal challenge on other issues. Management has determined that the result of the order had an immaterial impact to the financial statements of PSO. In November 2022, certain joint customers appealed the FERC denial of issues to the U.S. Court of Appeals for the District of Columbia Circuit. In January 2024, the court agreed with the FERC's order and denied the certain joint customers petition for review.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

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

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

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

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

The impact of the FERC's order on the pretax net income of PSO was not material.

5. EFFECTS OF REGULATION

Coal-Fired Generation Plants

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

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

Regulated Generating Unit to be Retired

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

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of December 31, 2023, of Northeastern Plant, Unit 3 that is planned for early retirement:

Net Book Value	Accelerated Depreciation	Cost of Removal	Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (a)
(dollars in millions)					
$ 104.5	$ 164.2	$ 20.5 (b)	2026	(c)	$ 15.0

(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.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2023	December 31, 2022	Remaining Recovery Period
Regulatory Assets:	(in millions)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	$ 88.5	$ 25.5	
Other Regulatory Assets Pending Final Regulatory Approval	0.1	0.1	
Total Regulatory Assets Currently Not Earning a Return	88.6	25.6	
Total Regulatory Assets Pending Final Regulatory Approval	88.6	25.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Under-recovered Fuel Costs	118.3	431.4	1 year
Plant Retirement Costs - Unrecovered Plant	89.9	94.7	23 years
Environmental Control Projects	22.5	23.9	17 years
Meter Replacement Costs	14.1	18.1	4 years
Storm-Related Costs	26.2	8.4	5 years
Other Regulatory Assets Approved for Recovery	8.4	9.5	various
Total Regulatory Assets Currently Earning a Return	279.4	586.0	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	62.6	55.2	12 years
Income Taxes Assets	18.3	13.2	(a)
Unrealized Loss on Forward Commitments	29.9	—	2 years
Other Regulatory Assets Approved for Recovery	11.5	14.5	various
Total Regulatory Assets Currently Not Earning a Return	122.3	82.9	
Total Regulatory Assets Approved for Recovery	401.7	668.9	
Total FERC Account 182.3 Regulatory Assets	$ 490.3	$ 694.5	

(a) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

	December 31, 2023	December 31, 2022	Remaining Refund Period
Regulatory Liabilities:	(in millions)		
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Tax Liabilities (a)	$ —	$ 51.3	
Total Regulatory Liabilities Currently Paying a Return	—	51.3	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	1.2	—	
Total Regulatory Liabilities Currently Not Paying a Return	1.2	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	1.2	51.3	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Tax Liabilities (a)	414.0	393.4	(b)
Total Regulatory Liabilities Currently Paying a Return	414.0	393.4	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Approved for Payment	4.0	13.2	various
Total Regulatory Liabilities Currently Not Paying a Return	4.0	13.2	
Total Regulatory Liabilities Approved for Payment	418.0	406.6	
Total FERC 254 Account Regulatory Liabilities	$ 419.2	$ 457.9	

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

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

COMMITMENTS

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

In accordance with the accounting guidance for "Commitments", the following table summarizes PSO's actual contractual commitments as of December 31, 2023:

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

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

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

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

PSO is jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to power purchase and sale activity.

Lease Obligations

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

ENVIRONMENTAL CONTINGENCIES

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 and sludge. 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. PSO currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

PSO maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. PSO also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cybersecurity incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by PSO. Coverage is generally provided by a combination of the protected cell of EIS and/or 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, including, but not limited to, liabilities relating to a cybersecurity incident. 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.

7. ACQUISITIONS

North Central Wind Energy Facilities

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs, on a fixed cost turn-key basis. PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. In total, the three wind facilities cost approximately $2 billion and consist of Traverse (998 MW), Maverick (287 MW) and Sundance (199 MW). Output from the NCWF serves retail load in PSO's Oklahoma service territory and both retail and FERC wholesale load in SWEPCo's service territories in Arkansas and Louisiana. The Oklahoma and Louisiana portions of the NCWF revenue requirement, net of PTC benefit, are recoverable through authorized riders until the amounts are reflected in base rates. The NCWF are subject to various regulatory performance requirements. If these performance requirements are not met, PSO would recognize a regulatory liability to refund retail customers.

In April 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Sundance during its development and construction for $270 million. Sundance was placed in-service in April 2021. In September 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Maverick during its development and construction for $383 million. Maverick was placed in-service in September 2021. In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction for $1.2 billion. Traverse was placed in-service in March 2022. Immediately following the acquisitions, PSO and SWEPCo liquidated the entities and simultaneously distributed the assets in proportion to their undivided ownership interests. PSO and SWEPCo apply the joint plant accounting model to account for their respective undivided interests in the assets, liabilities, revenues and expenses of the NCWF projects.

Rock Falls Wind Facility

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

8. BENEFIT PLANS

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

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

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
Assumption	2023	2022	2023	2022
Discount Rate	5.15 %	5.50 %	5.15 %	5.50 %
Interest Crediting Rate	4.00 %	4.25 %	NA	NA
Rate of Compensation Increase	5.20 % (a)	5.15 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

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

For 2023, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of benefit costs are shown in the following table:

	Pension Plans		OPEB	
	Year Ended December 31,			
Assumption	2023	2022	2023	2022
Discount Rate	5.50 %	2.90 %	5.50 %	2.90 %
Interest Crediting Rate	4.25 %	4.00 %	NA	NA
Expected Return on Plan Assets	7.50 %	5.25 %	7.25 %	5.50 %
Rate of Compensation Increase	5.20 % (a)	5.15 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

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

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

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

Significant Concentrations of Risk within Plan Assets

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

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

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

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 192.3	$ 252.6	$ 45.7	$ 54.4
Service Cost	5.5	7.4	0.3	0.4
Interest Cost	10.7	7.0	2.4	1.5
Actuarial (Gain) Loss	13.6	(52.9)	0.4	(5.2)
Benefit Payments	(19.9)	(21.8)	(7.6)	(7.9)
Participant Contributions	—	—	2.5	2.5
Benefit Obligation as of December 31,	$ 202.2	$ 192.3	$ 43.7	$ 45.7
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 218.5	$ 286.2	$ 85.4	$ 114.0
Actual Gain (Loss) on Plan Assets	24.0	(46.0)	9.9	(23.2)
Company Contributions	0.1	0.1	—	—
Participant Contributions	—	—	2.5	2.5
Benefit Payments	(19.9)	(21.8)	(7.6)	(7.9)
Fair Value of Plan Assets as of December 31,	$ 222.7	$ 218.5	$ 90.2	$ 85.4
Funded Status as of December 31,	$ 20.5	$ 26.2	$ 46.5	$ 39.7

	Pension Plans December 31, 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ 21.8	$ 27.6	$ 46.5	$ 39.7
Miscellaneous Current and Accrued Liabilities – Short-term Benefit Liability	(0.1)	(0.1)	—	—
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(1.2)	(1.3)	—	—
Funded Status	$ 20.5	$ 26.2	$ 46.5	$ 39.7

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in regulatory assets and the items attributable to the change in these components:

	Pension Plans December 31, 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
Components	(in millions)			
Net Actuarial Loss	$ 46.7	$ 38.8	$ 17.5	$ 22.0
Prior Service Credit	—	—	(1.6)	(5.6)
Recorded as				
Regulatory Assets	$ 46.7	$ 38.8	$ 15.9	$ 16.4

	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 7.9	$ 6.7	$ (3.7)	$ 24.1
Amortization of Actuarial Loss	—	(2.9)	(0.8)	—
Amortization of Prior Service Credit	—	—	4.0	4.4
Change for the Year Ended December 31,	$ 7.9	$ 3.8	$ (0.5)	$ 28.5

Determination of Pension Expense

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

Pension and OPEB Assets

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

Pension Plan December 31, 2023	Pension Plan 2021	OPEB 2023	OPEB 2021
5.4 %	5.3 %	5.4 %	5.5 %

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

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

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

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

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

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

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

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

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

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

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

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

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	December 31, 2023	2022
	(in millions)	
Qualified Pension Plan	$ 186.6	$ 179.1
Nonqualified Pension Plans	1.2	1.2
Total	$ 187.8	$ 180.3

Obligations in Excess of Fair Values

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

Projected Benefit Obligation

	December 31, 2023	2022
	(in millions)	
Projected Benefit Obligation	$ 1.4	$ 1.5
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (1.4)	$ (1.5)

Accumulated Benefit Obligation

	December 31, 2023	2022
	(in millions)	
Accumulated Benefit Obligation	$ 1.2	$ 1.2
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (1.2)	$ (1.2)

Estimated Future Benefit Payments and Contributions

PSO expects contributions and payments for the pension plans to be immaterial during 2024. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, PSO may also make additional discretionary contributions to maintain the funded status of the plan.

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

	Estimated Payments: Pension Plans	OPEB
	(in millions)	
2024	$ 19.7	$ 6.7
2025	19.2	7.1
2026	19.4	7.0
2027	19.3	6.8
2028	19.0	6.5
Years 2029 to 2033, in Total	81.0	30.2

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Years Ended December 31,			
	2023	2022	2023	2022
	(in millions)			
Service Cost	$ 5.5	$ 7.4	$ 0.3	$ 0.4
Interest Cost	10.7	7.0	2.4	1.5
Expected Return on Plan Assets	(18.3)	(13.4)	(5.9)	(6.1)
Amortization of Prior Service Credit	—	—	(4.0)	(4.4)
Amortization of Net Actuarial Loss	—	2.9	0.8	—
Net Periodic Benefit Cost (Credit)	(2.1)	3.9	(6.4)	(8.6)
Capitalized Portion	(2.5)	(3.2)	(0.1)	(0.2)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (4.6)	$ 0.7	$ (6.5)	$ (8.8)

American Electric Power System Retirement Savings Plan

PSO participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions to the retirement savings plans for the years ended December 31, 2023 and 2022 were $5 million and $5 million, respectively.

9. BUSINESS SEGMENTS

PSO has one reportable segment, an electricity generation, transmission and distribution business. PSO's other activities are insignificant.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of PSO.

PSO is exposed to certain market risks as major power producer and participant 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 PSO 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, PSO primarily employs 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.

PSO utilizes 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. PSO utilizes 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. PSO also utilizes derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

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

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2023	Volume December 31, 2022	Unit of Measure
	(in millions)		
Commodity:			
Power	4.1	2.9	MWhs
Natural Gas	34.9	1.9	MMBtus
Heating Oil and Gasoline	0.7	0.9	Gallons
Interest Rate on Long-term Debt	$ —	$ 200.0	USD

Cash Flow Hedging Strategies

PSO utilizes 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. PSO does not hedge all commodity price risk.
PSO utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. PSO also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. PSO does 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, PSO applies 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," PSO reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, PSO is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for PSO as of December 31, 2023 and 2022. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for PSO as of December 31, 2023 and 2022.

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

	December 31, 2023		
Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Derivative Instrument Assets	$ 19.7	$ (0.7)	$ 19.0
Long-Term Portion of Derivative Instrument Assets	—	—	—
Derivative Instrument Liabilities	30.7	(0.8)	29.9
Long-Term Portion of Derivative Instrument Liabilities	1.0	—	1.0

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	December 31, 2022				
			(in millions)		
Derivative Instrument Assets	$ 24.1	$ 1.6	$ 25.7	$ (0.4)	$ 25.3
Long-Term Portion of Derivative Instrument Assets	—	—	—	—	—
Derivative Instrument Liabilities	2.1	—	2.1	(0.5)	1.6
Long-Term Portion of Derivative Instrument Liabilities	—	—	—	—	—

(a) Derivative instruments within these categories are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2023	2022
	(in millions)	
Operation Expenses	$ —	$ 0.8
Maintenance Expenses	(0.1)	0.8
Other Regulatory Assets (a)	(29.8)	3.6
Other Regulatory Liabilities (a)	88.7	98.5
Total Gain on Risk Management Contracts	$ 58.8	$ 103.7

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

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 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 Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), PSO initially reports the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income 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 Operating Revenues or Operation Expenses on the statements of income or in Other Regulatory Assets or Other Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2023 and 2022, PSO did not apply cash flow hedging to outstanding power derivatives.

PSO reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long-term Debt on the statements of income in those periods in which hedged interest payments occur. During the years ended 2023 and 2022, PSO applied cash flow hedging to outstanding interest rate derivatives.

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

Impact of Cash Flow Hedges on the Balance Sheets

December 31, 2023		December 31, 2022	
Interest Rate			
AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
(in millions)			
$ (0.2)	$ —	$ 1.3	$ 0.1

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Credit-Risk-Related Contingent Features

Credit Downgrade Triggers

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. PSO has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. PSO had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2023 and 2022.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by PSO 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. PSO's derivative contracts with cross-acceleration provisions outstanding as of December 31, 2023 and 2022 were not material.

Cross-Default Triggers

In addition, a majority of PSO's 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. PSO had derivative contracts with cross-default provisions in a net liability position of $29 million and no cash collateral posted as of December 31, 2023. PSO's derivative contracts with cross-default provisions outstanding as of December 31, 2022 were not material.

11. <u>FAIR VALUE MEASUREMENTS</u>

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 Long-term Debt are summarized in the following table:

December 31,			
2023		2022	
Book Value	Fair Value	Book Value	Fair Value
(in millions)			
$ 2,397.2	$ 2,154.3	$ 1,923.8	$ 1,635.8

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, PSO's 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.

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

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

(a) 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."

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

Year Ended December 31, 2023	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2022	$ 23.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	29.8
Settlements	(53.4)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	18.5
Balance as of December 31, 2023	$ 18.6

Year Ended December 31, 2022	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2021	$ 12.1
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	24.2
Settlements	(36.3)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	23.7
Balance as of December 31, 2022	$ 23.7

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) 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:

December 31, 2023

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in millions)						
FTRs	$ 19.7	$ 1.1	Discounted Cash Flow	Forward Market Price	$ (25.45)	$ 4.80	$ (4.33)

December 31, 2022

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

(a) Represents market prices in dollars per MWh.
(b) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to FTRs as of December 31, 2023 and 2022:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

Income Tax Expense

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

	Years Ended December 31,	
	2023	2022
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (65.1)	$ (0.4)
Deferred	6.5	(46.1)
Total	(58.6)	(46.5)
Charged (Credited) to Non-Operating Income, Net:		
Current	4.6	(2.9)
Deferred	0.4	0.2
Total	5.0	(2.7)
Income Tax Expense	$ (53.6)	$ (49.2)

The following is a reconciliation between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31,	
	2023	2022
	(in millions)	
Net Income	$ 208.9	$ 167.6
Income Tax Expense	(53.6)	(49.2)
Pretax Income	$ 155.3	$ 118.4
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 32.6	$ 24.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Investment Tax Credit Amortization	(1.4)	(1.6)
Production Tax Credits	(64.3)	(47.7)
State and Local Income Taxes, Net	3.5	4.3
Tax Reform Excess ADIT Reversal	(23.3)	(25.4)
Federal Return to Provision	0.6	(3.7)
Other	(1.3)	—
Income Tax Expense	$ (53.6)	$ (49.2)
Effective Income Tax Rate	(34.5) %	(41.6) %

Net Deferred Tax Liability

The following table shows elements of PSO's net deferred tax liability and significant temporary differences:

	December 31,	
	2023	2022
	(in thousands)	
Deferred Tax Assets	$ 282.3	$ 225.0
Deferred Tax Liabilities	(1,113.5)	(1,013.6)
Net Deferred Tax Liabilities	$ (831.2)	$ (788.6)
Property Related Temporary Differences	$ (817.2)	$ (763.3)
Amounts Due to Customers for Future Income Taxes	88.6	96.0
Deferred State Income Taxes	(122.6)	(81.9)
Regulatory Assets	(83.8)	(140.2)
Tax Credit Carryforward	53.8	54.3
Net Operating Loss Carryforward	25.3	25.8
All Other, Net	24.7	20.7
Net Deferred Tax Liabilities	$ (831.2)	$ (788.6)

Tax Credit Carryforward

As of December 31, 2023, PSO has federal tax credit carryforwards in the amount of $54 million. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041. PSO anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

State net income tax operating losses sustained in 2017, 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused state income tax credits. As of December 31, 2023 and December 31, 2022, PSO had state tax credit carryforwards of $40 million and $39 million, respectively. Management anticipates future taxable income will be sufficient to realize the tax benefits of the state tax credits before they expire unused.

Net Income Tax Operating Loss Carryforward

As of December 31, 2023, PSO has Oklahoma state net income tax operating loss carryforward of $947 million. As a result, PSO recognized deferred state income tax benefits. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires.

Federal and State Income Tax Audit Status

The statute of limitations for the IRS to examine PSO and other AEP subsidiaries originally filed federal return has expired for tax years 2016 and earlier. PSO and other AEP subsidiaries have agreed to extend the statute of limitations on the 2017-2019 tax returns to October 31, 2024, to allow time for our refund claim to be approval by the Congressional Joint Committee on Taxation. The statute of limitations for the 2020 return is set to naturally expire in October 2024 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. PSO and other AEP subsidiaries have received and agreed to immaterial IRS proposed adjustments on the 2017 tax return. The exam is complete, and PSO and AEP subsidiaries are currently waiting on the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

PSO and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and PSO and other AEP 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 and State Tax Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. As further significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, PSO and other AEP subsidiaries will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

In December 2022, the IRS released Notice 2023-7, which provided initial CAMT guidance that PSO and other AEP subsidiaries can begin to rely on in 2023. Notably, the interim guidance in Notice 2023-7 confirmed the CAMT depreciation adjustment includes tax depreciation that is capitalized to inventory under §263A and recovered as part of cost of goods sold, providing significant relief to PSO and other AEP subsidiaries' potential CAMT exposure. In September 2023, the IRS released Notice 2023-64, which clarifies and supplements items in Notice 2023-7 and stated that additional guidance in the form of proposed regulations is expected. PSO and other AEP subsidiaries will continue to monitor and assess any additional guidance.

PSO and other AEP subsidiaries expect to be applicable corporations for purposes of the CAMT beginning in 2023. CAMT cash taxes are expected to be partially offset by regulatory recovery, the utilization of tax credits and additionally the cash inflow generated by the sale of tax credits. The sale of tax credits will be presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. PSO and other AEP subsidiaries will present the loss on sale of tax credits through income tax expense.

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

13. LEASES

PSO leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. PSO does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain PSO will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, PSO measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating and Finance lease rental costs are generally charged to Operation Expense and Maintenance Expense in accordance with rate-making treatment for regulated operations. Lease costs associated with capital projects are included in Utility Plant on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs were as follows:

	Years Ended December 31,	
	2023	2022
	(in millions)	
Operating Lease Cost	$ 13.5	$ 11.8
Finance Lease Cost:		
Amortization of Right-of-Use Assets	3.3	3.2
Interest on Lease Liabilities	0.7	0.6
Total Lease Rental Costs (a)	$ 17.5	$ 15.6

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

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

	December 31,	
	2023	2022
Weighted-Average Remaining Lease Term (years):		
Operating Leases	23.85	23.90
Finance Leases	5.76	6.02
Weighted-Average Discount Rate:		
Operating Leases	3.72 %	3.43 %
Finance Leases	5.14 %	4.63 %

	Year Ended December 31,	
	2023	2022
	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating Cash Flows from Operating Leases	$ 12.5	$ 10.5
Operating Cash Flows from Finance Leases	4.0	3.8
Non-cash Acquisitions Under Operating Leases	$ 15.5	$ 46.0

The following tables show property, plant and equipment under finance leases, operating leases and related obligations recorded on PSO's balance sheets:

	December 31,	
	2023	2022
	(in millions)	
Property, Plant and Equipment Under Finance Leases		
Utility Plant (a)	$ 13.8	$ 15.0
Obligations Under Finance Leases		
Noncurrent	$ 10.7	$ 11.7
Current	3.1	3.3
Total Obligations Under Finance Leases	$ 13.8	$ 15.0

(a) Includes $12 million and $11 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

	December 31,	
	2023	2022
	(in millions)	
Property, Plant and Equipment Under Operating Leases		
Utility Plant (a)	$ 112.8	$ 106.1
Obligations Under Operating Leases		
Noncurrent	$ 106.8	$ 99.3
Current	10.1	8.9
Total Obligations Under Operating Leases	$ 116.9	$ 108.2

(a) Includes $28 million and $22 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

Future minimum lease payments consisted of the following as of December 31, 2023:

	Finance Leases	Operating Leases
	(in millions)	
2024	$ 3.7	$ 12.2
2025	2.9	11.1
2026	2.5	10.3
2027	2.0	9.3
2028	1.7	7.9
After 2028	3.3	129.1
Total Future Minimum Lease Payments	16.1	179.9
Less: Imputed Interest	2.3	63.0
Estimated Present Value of Future Minimum Lease Payments	$ 13.8	$ 116.9

Master Lease Agreements

PSO leases 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, PSO is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2023, the maximum potential loss by PSO for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $5 million.

Lessor Activity

PSO's lessor activity was immaterial as of and for the twelve months ended December 31, 2023 and December 31, 2022, respectively.

14. FINANCING ACTIVITIES

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	2022		Outstanding as of December 31, 2023		2022
Senior Unsecured Notes	2025-2051	4.05%	2.20%-6.63%	2.20%-6.63%	$	2,275.0	$	1,800.0
Other Long-term Debt	2025-2027	6.65%	3.00%-6.71%	3.00%-5.75%		127.0		127.5
Unamortized Discount, Net						(4.8)		(3.7)
Total Long-term Debt Outstanding					$	2,397.2	$	1,923.8

As of December 31, 2023, long-term debt was payable as follows:

		(in millions)
2024	$	0.6
2025		250.6
2026		50.6
2027		0.2
2028		—
After 2028		2,100.0
Principal Amount		2,402.0
Unamortized Discount, Net		(4.8)
Total Long-term Debt	$	2,397.2

Dividend Restrictions

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

All of the dividends declared by PSO 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.

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

The most restrictive dividend limitation for PSO is through the credit agreements. As of December 31, 2023, the maximum amount of restricted net assets of PSO that may not be distributed to the Parent in the form of a loan, advance or dividend was $1.2 billion.

The credit agreement covenant restrictions can limit the ability of PSO to pay dividends out of retained earnings. As of December 31, 2023, the amount of any such restriction was $1 million.

Corporate Borrowing Program – AEP System

PSO uses a corporate borrowing program to meet its short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2023 and 2022 are included in Notes Payable to Associated Companies on the balance sheets. PSO's money pool activity and corresponding authorized borrowing limits are described in the following table:

Years ended December 31,		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		Borrowings from the Utility Money Pool as of December 31,		Authorized Short-term Borrowing Limit
							(in millions)					
2023	$	375.0	$	121.5	$	92.5	$	49.6	$	54.4	$	750.0
2022		364.2		432.5		224.5		402.8		364.2		400.0

The maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2023	5.79 %	4.66 %	5.81 %	4.93 %	5.51 %	5.35 %
2022	5.28 %	0.46 %	2.19 %	0.10 %	2.65 %	0.75 %

Interest expense and interest income related to the Utility Money Pool financing relationship are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on the statements of income. The interest expense related to the corporate borrowing programs were $2 million and $6 million for the years ended December 31, 2023 and 2022, respectively, and interest income related to the corporate borrowing programs were $2 million and $258 thousand for the years ended December 31, 2023 and 2022.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, PSO sells, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for PSO's receivables. The costs of customer accounts receivable sold are reported in Other Deductions on PSO's statements of income. PSO manages and services its customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for PSO and retains the remainder.

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables. The agreement was amended in August 2023 to increase the commitment from $750 million and expires in September 2025. As of December 31, 2023, PSO was in compliance with all requirements under the agreement.

The amount of accounts receivable and accrued utility revenues under the sale of receivables agreement as of December 31, 2023 and 2022 were $135 million and $156 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $15 million and $7 million for the years ended December 31, 2023 and 2022, respectively.

The proceeds on the sale of receivables to AEP Credit were $1.9 billion and $1.8 billion for the years ended December 31, 2023 and 2022, respectively.

15. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes and Investment and Production Tax Credits" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Intercompany Billings

PSO and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement.

Joint License Agreement

AEPTCo entered into a 50-year joint license agreement with PSO, allowing either party to occupy the granting party's facilities or real property. After the expiration of the agreement, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. PSO recorded income related to this agreement in Operating Revenues on the statements of income. The impact of the joint license agreement for the years ended December 31, 2023 and 2022 was not material.

Sales and Purchases of Property

PSO had affiliated sales and purchases of electric property amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2023 and 2022 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. In 2023, there were no charitable contributions made to the AEP Foundation. In 2022, PSO made a $6 million charitable contribution to the AEP Foundation recorded in Donations on the statements of income.

Transmission Service Charges

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and SWEPCo. Under the TCA, AEPSC is responsible for monitoring the reliability of their transmission systems and administering the OATT. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.
PSO recorded net transmission service charges discussed above of $100 million and $111 million, for the years ended December 31, 2023 and 2022, respectively, in Operation Expense on the statements of income. Refer to the Affiliated Revenues section below for amounts related to these transactions.

Affiliated Revenues

The following table shows the revenues derived from other revenues for the years ended December 31, 2023 and 2022:

Related Party Revenues	Years Ended December 31, 2023	2022
	(in millions)	
Other Revenues	$ 1.2	$ 2.9

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation

PSO provides for depreciation of Utility Plant, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates by functional class:

Year	Steam	Other Generation	Transmission	Distribution	General
			(in percentages)		
2023	3.3 %	2.7 %	2.6 %	2.9 %	6.8 %
2022	3.5 %	2.7 %	2.5 %	2.9 %	6.8 %

The composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation on the balance sheets. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations

In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Traverse assets in proportion to their undivided ownership interests. Traverse was placed in-service in March 2022. As a result, PSO incurred additional ARO liabilities of $13 million. See the "North Central Wind Energy Facilities" section of Note 7 for additional information.

The following is a reconciliation of the 2023 and 2022 aggregate carrying amounts of ARO:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in millions)			
2023	$ 75.7	$ 4.7	$ 5.8	$ (1.2)	$ (0.8)	$ 84.2 (a)(b)(c)
2022	57.6	4.1	12.8	(0.7)	1.9	75.7 (a)(b)(c)

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to asbestos removal.
(c) Includes ARO related to wind

Jointly-owned Electric Facilities

PSO has an electric facility that is jointly-owned with SWEPCo. Using its own financing, PSO is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest. PSO's proportionate share of the operating costs associated with this facility are included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

	Fuel Type	Percent of Ownership	Share as of December 31, 2023: Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
North Central Wind Energy Facilities (a)(b)	Wind	45.5 %	$ 906.3	$ 2.4	$ 54.1

	Fuel Type	Percent of Ownership	Share as of December 31, 2022: Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
North Central Wind Energy Facilities (a)(b)	Wind	45.5 %	$ 889.3	$ 9.1	$ 28.1

(a) Operated by PSO
(b) PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively.

17. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The tables below represent revenues from contracts with customers, net of respective provisions for refund, by type of revenue for PSO:

	Years Ended December 31, 2023	2022
	(in millions)	
Retail Revenues:		
Residential Revenues	$ 831.2	$ 816.3
Commercial Revenues	538.8	489.2
Industrial Revenues	423.1	372.5
Other Retail Revenues	112.8	102.9
Total Retail Revenues	1,905.9	1,780.9
Wholesale Revenues:		
Generation Revenues	20.1	42.7
Transmission Revenues	37.5	39.2
Total Wholesale Revenues	57.6	81.9
Other Revenues from Contracts with Customers (a)	26.0	30.3
Total Revenues from Contracts with Customers	1,989.5	1,893.1
Other Revenues:		
Alternative Revenues	0.5	(1.0)
Total Other Revenues	0.5	(1.0)
Total Operating Revenues	$ 1,990.0	$ 1,892.1

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

PSO 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. PSO 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 PSO are summarized as follows:

Retail Revenues

PSO has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between PSO and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

PSO has performance obligations to sell electricity to wholesale customers from generation assets in SPP. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

PSO has performance obligations to transmit electricity to wholesale customers through assets it owns and operates. The performance obligation to provide transmission services in SPP encompasses a time frame greater than a year, where the performance obligation within each RTO is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP.

PSO within the SPP region collects revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

PSO, SWEPCo and AEPSC are parties to the TCA by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. Affiliate revenues as a result of the TCA are reflected as Transmission Revenues in the disaggregated revenues table above.

Contract Assets and Liabilities

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

When PSO 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. PSO's contract liabilities typically arise from services provided under joint use agreements for utility poles. PSO 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 PSO's balance sheets within the Customer Accounts Receivable line item. PSO'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. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on PSO's balance sheets were $12 million and $19 million, as of December 31, 2023 and 2022.

Contract Costs

Contract costs to obtain or fulfill a contract for PSO are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current 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 income statements. PSO did not have material contract costs as of December 31, 2023 and 2022.

Name of Respondent: Public Service Company of Oklahoma	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					1,273,874		1,273,874		
4	Total (lines 2 and 3)					1,273,874		1,273,874	167,604,392	168,878,266
5	Balance of Account 219 at End of Preceding Quarter/Year					1,273,874		1,273,874		
6	Balance of Account 219 at Beginning of Current Year					1,273,874		1,273,874		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income					1,299,401		1,299,401		
8	Current Quarter/Year to Date Changes in Fair Value					(2,805,090)		(2,805,090)		
9	Total (lines 7 and 8)					(1,505,689)		(1,505,689)	208,852,129	207,346,440
10	Balance of Account 219 at End of Current Quarter/Year					(231,815)		(231,815)		

Name of Respondent: Public Service Company of Oklahoma	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)	7,202,975,485	7,202,975,485					
4	Property Under Capital Leases	126,530,835	126,530,835					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	651,058,667	651,058,667					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	7,980,564,987	7,980,564,987					
9	Leased to Others							
10	Held for Future Use	519,733	519,733					
11	Construction Work in Progress	319,053,347	319,053,347					
12	Acquisition Adjustments	3,490,722	3,490,722					
13	Total Utility Plant (8 thru 12)	8,303,628,789	8,303,628,789					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,225,710,913	2,225,710,913					
15	Net Utility Plant (13 less 14)	6,077,917,876	6,077,917,876					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	2,127,136,647	2,127,136,647					
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	95,083,544	95,083,544					
22	Total in Service (18 thru 21)	2,222,220,191	2,222,220,191					
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	3,490,722.00	3,490,722					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,225,710,913	2,225,710,913					

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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: Public Service Company of Oklahoma	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	193,945,162	25,820,441	7,552,978			212,212,625
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	193,945,162	25,820,441	7,552,978			212,212,625
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	6,072,913					6,072,913
9	(311) Structures and Improvements	69,872,794	4,669,230	706,544			73,835,480
10	(312) Boiler Plant Equipment	716,404,665	11,988,157	3,707,619			724,685,203
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	408,374,624	14,251,320	1,309,733			421,316,211
13	(315) Accessory Electric Equipment	82,148,497	2,566,456	278,277			84,436,676
14	(316) Misc. Power Plant Equipment	47,638,979	2,546,286	285,321			49,899,944
15	(317) Asset Retirement Costs for Steam Production	24,521,893	(11,239)				24,510,654
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,355,034,365	36,010,210	6,287,494			1,384,757,081
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						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
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	360,325	87,000				447,325
38	(341) Structures and Improvements	5,771,319	313,827				6,085,146
39	(342) Fuel Holders, Products, and Accessories	11,411,270					11,411,270
40	(343) Prime Movers						
41	(344) Generators	982,837,755	269,389,857	3,988,468			1,248,239,144
42	(345) Accessory Electric Equipment	15,236,525	804	1,057,620			14,179,709
43	(346) Misc. Power Plant Equipment	3,097,567	383,504	6,127			3,474,944
44	(347) Asset Retirement Costs for Other Production	20,507,245	5,835,983				26,343,228
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,039,222,006	276,010,975	5,052,215			1,310,180,766
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,394,256,371	312,021,185	11,339,709			2,694,937,847
47	3. Transmission Plant						
48	(350) Land and Land Rights	51,077,492	1,803,220	4,774			52,875,938
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	21,291,882	2,143,821	741,395			22,694,308
50	(353) Station Equipment	503,180,625	22,886,838	2,065,520		(1,439,153)	522,562,790
51	(354) Towers and Fixtures	17,454,600	1,920,319	385,690			18,989,229
52	(355) Poles and Fixtures	362,630,211	37,270,231	9,834,604			390,065,838
53	(356) Overhead Conductors and Devices	208,515,531	12,590,068	2,755,264			218,350,335
54	(357) Underground Conduit	113,732	1,730,767				1,844,499
55	(358) Underground Conductors and Devices	88,788	161,206				249,994
56	(359) Roads and Trails		770,547				770,547
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,164,352,861	81,277,017	15,787,247		(1,439,153)	1,228,403,478
59	4. Distribution Plant						
60	(360) Land and Land Rights	10,910,867	120,872	38			11,031,701
61	(361) Structures and Improvements	24,473,891	2,329,981	44,372			26,759,500
62	(362) Station Equipment	529,565,942	36,252,235	2,086,612		1,439,153	565,170,718
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	541,423,198	52,332,831	5,109,050			588,646,979
65	(365) Overhead Conductors and Devices	560,234,164	65,032,740	6,914,174			618,352,730
66	(366) Underground Conduit	113,994,455	8,095,065	65,165			122,024,355
67	(367) Underground Conductors and Devices	431,263,146	26,379,186	1,145,217			456,497,115
68	(368) Line Transformers	426,219,685	41,164,147	9,551,011			457,832,821
69	(369) Services	316,116,079	14,050,411	1,212,242			328,954,248
70	(370) Meters	121,211,761	7,000,035	1,954,510			126,257,286
71	(371) Installations on Customer Premises	56,015,109	6,556,409	2,411,143			60,160,375
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	84,415,068	4,732,955	600,179			88,547,844
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,215,843,365	264,046,867	31,093,713		1,439,153	3,450,235,672
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
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	7,596,021	692,799			218,529	8,507,349
87	(390) Structures and Improvements	75,240,986	14,402,654	2,238,589			87,405,051
88	(391) Office Furniture and Equipment	1,891,449	1,095,359	68,498			2,918,310
89	(392) Transportation Equipment	1,886,758	30,543	16,989			1,900,312
90	(393) Stores Equipment	2,613,773	322,412	444,205			2,491,980
91	(394) Tools, Shop and Garage Equipment	36,489,037	337,732	9,185			36,817,584
92	(395) Laboratory Equipment	782,530		4,030			778,500
93	(396) Power Operated Equipment	616,371	65,715				682,086
94	(397) Communication Equipment	102,455,745	8,313,451	1,287,833			109,481,363
95	(398) Miscellaneous Equipment	15,793,807	943,746	27,632			16,709,921
96	SUBTOTAL (Enter Total of lines 86 thru 95)	245,366,477	26,204,411	4,096,961		218,529	267,692,456
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	552,074					552,074
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	245,918,551	26,204,411	4,096,961		218,529	268,244,530
100	TOTAL (Accounts 101 and 106)	7,214,316,310	709,369,921	69,870,608		218,529	7,854,034,152
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)	7,214,316,310	709,369,921	69,870,608		218,529	7,854,034,152

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Name of Respondent: Public Service Company of Oklahoma	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 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)
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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)
45						
46						
47	TOTAL					

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Name of Respondent: Public Service Company of Oklahoma	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 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	Items Under $250,000			519,733.00
21	Other Property:			
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	TOTAL			519,733

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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	116th&Peoria-UpgradeTransfrmrs	1,494,847
2	135MW Wind Flat Ridge IV	1,692,648
3	150MW PSO Solar Algodon	1,232,584
4	153MW Wind Flat Ridge V	1,503,985
5	189MW PSO Solar Pixley	1,752,317
6	265MW PSO Wind Lazbuddie	2,493,832
7	ADMS Imp DSN DNEX-PSO D	5,986,028
8	BInger Tap D CI	1,340,092
9	Binger Tap PSO CI	6,059,693
10	Boswell D-Station Work	4,483,163
11	CatoosaBlueCircle NTC CI	1,410,889
12	Chisholm T TTMP 2023 CI	3,231,762
13	ci 114	(2,995,860)
14	CIS-Common Deployment-PSO D	5,179,566
15	Clint City to Clint Jct PSO CI	3,833,440
16	Clinton City PSO D CI	1,819,411
17	Clinton Laydown Yard	2,133,213
18	Corp Prgrm Billing - PSO Trans	1,338,146
19	D/PO/Capital Blanket - PSO	3,992,108
20	D-Line Technology for 2022	1,685,002
21	Ds Pso Anda	1,451,605
22	Ds-Pso-Ai Line Reclosers	7,731,313
23	DX Sunray PSO CI	1,559,909
24	DX Sunray Station PSO D	6,087,754
25	Ed-Ci-Psoco-D Ast Imp	14,328,987
26	Ed-Ci-Psoco-D Cust Mtr	1,071,176
27	Ed-Ci-Psoco-D Cust Serv	3,112,649
28	Ed-Ci-Psoco-D Ppr	3,480,202
29	Elgin Jct D-Station Work	4,963,037
30	EV Chargers for GL BU 167	1,166,851
31	Ft Sill to LES PSO CI	2,282,154
32	Hobart City to Snyder PSO CI	1,317,457
33	LES PSO CI	1,370,735
34	N12 1B Turbine Failure 2023	11,810,681
35	NCEF-CI-PSO-G-PPB	2,090,969
36	Okmulgee City D-Station Work	2,199,956
37	Pittsburg-Sunnyside PSO CI	2,908,892
38	PSO CVR Distribution Line 2023	3,493,221
39	PSO DACR Distribution Line2022	2,177,723
40	PSO DACR Distribution Sch Line	6,942,680
41	PSO DACR DistributionLine 2021	1,197,759
42	PSO DACR D-Line Tech 2022-2023	1,699,615

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
43	PSO DACR Station 2022	1,757,120
44	PSO DACR Station 2022-2023	4,775,087
45	PSO Distr Pre Eng Parent	1,334,991
46	PSO LED Lgt. Upgrade 2022-2026	19,526,547
47	PSO Radio Coverage Improvement	1,655,600
48	PSO Region Failures- D Station	1,160,640
49	PSO Station Rehab Upgrade 2022	4,487,919
50	PSO Trans Pre Eng Parent	1,701,412
51	PSO Transmission	9,392,382
52	PSO-D Service Restoration Blkt	2,317,658
53	PSO-D Small Cap Adds Blkt	6,453,449
54	PSO-D Spare Equipment CI	1,331,689
55	PSO-D Spare Equipment CI	3,261,182
56	PSO-D Telecom	9,787,519
57	PSO-D Third Party Work Blkt	2,887,324
58	PSO-T BlnktProj Under $3M	2,055,430
59	PSO-T Spare Equipment CI	3,830,199
60	PSO-T Spare Equipment CI	1,744,554
61	Purchase Tulsa Alsuma Garage	2,020,624
62	Ramona Mainspring Station Work	1,032,285
63	Replace U4 Noz Block & Blades	1,865,973
64	RETUBE CONDENSER	1,662,804
65	Ridge Road D-Station Work	1,570,249
66	Riverside PSO CI	3,344,963
67	Riverside to S Hudson PSO CI	3,016,897
68	SS-CI-PSOCo-D GEN PLT	3,844,988
69	SW Power Station PSO CI	6,219,474
70	SW Station D CI	5,046,303
71	SWS Cooling Tower Replace U1	6,207,070
72	T/PO/Capital Blanket - PSO	4,064,072
73	T/PSO/Transmission Work	1,816,902
74	T/PSO/Transmission Work 2.0	1,436,436
75	TRANSMISSION WORK	10,102,023
76	Weleetka PSO CI	2,113,189
77	Weleetka Station D CI	1,908,409
78	White Rock Wind East PSO CI	2,520,901
79	WS-CI-PSOCo-G PPB	15,074,534
80	Other Minor Projects Which is under 5% or $1,000,000	30,612,358
43	Total	319,053,347
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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	1,913,521,616	1,913,521,616		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	222,024,619	222,024,619		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,632,857	1,632,857		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	252,078	252,078		
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)	223,909,554	223,909,554		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(62,317,630)	(62,317,630)		
13	Cost of Removal	(46,002,671)	[a](46,002,671)		
14	Salvage (Credit)	2,538,735	[b]2,538,735		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(105,781,566)	(105,781,566)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	95,487,043	[c]95,487,043		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,127,136,647	2,127,136,647		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	804,399,202	804,399,202		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	213,653,077	213,653,077		
25	Transmission	239,157,913	239,157,913		
26	Distribution	808,966,823	808,966,823		
27	Regional Transmission and Market Operation				
28	General	60,959,632	60,959,632		
29	TOTAL (Enter Total of lines 20 thru 28)	2,127,136,647	2,127,136,647		

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FOOTNOTE DATA

(a) Concept: CostOfRemovalOfPlant
Includes $17,756,461 of removal cost in retirement work in progress (RWIP).
(b) Concept: SalvageValueOfRetiredPlant
Includes ($2,170,809) of salvage in retirement work in progress (RWIP).
(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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								
17								
18								
19								
20								
21								
22								
23								
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25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								

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)
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 $		Total					

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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)	10,868,527	31,456,037	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	730,099	2,219,109	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	86,186,152	74,657,137	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	20,188,736	29,350,484	Electric
8	Transmission Plant (Estimated)	747,494	807,345	Electric
9	Distribution Plant (Estimated)	1,673,567	1,041,799	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,031,020	[a]979,263	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	109,826,969	106,836,028	
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	121,425,595	140,511,174	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other Includes Customer Accounts and Administrative and General Expenses (applies to both beginning and ending balances).

Name of Respondent: Public Service Company of Oklahoma	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.	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	390,044		37,382		37,382		37,382		971,933		1,474,123	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									36,939		36,939	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Unknown												
10	Other												
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	3,196										3,196	
19	Other:												
20	Allowances Used												
20.1	Plant Transfer Allowance Adjustment												
21	Cost of Sales/Transfers:												
22	Surrenders												
23	Consent Decree Surrenders												
24	Unknown												
25	Other												
26													
27													
28	Total												
29	Balance-End of Year	386,848		37,382		37,382		37,382		1,008,872		1,507,866	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		22										22

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)
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
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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Name of Respondent: Public Service Company of Oklahoma	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 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	2,969	1,262,825	2,212								5,181	1,262,825
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	141										141	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Kaxe Holdings LLC	1,480	1,068,500									1,480	1,068,500
10	Other												
11													
12													
13													
14													
15	Total	1,480	1,068,500									1,480	1,068,500
16													
17	Relinquished During Year:												
18	Charges to Account 509	4,224	2,289,742									4,224	2,289,742
19	Other:												
20	Allowances Used												
20.1	Plant Transfer Allowance Adjustment												
21	Cost of Sales/Transfers:												
22	Surrenders												
23	Unknown												
24	Consent Decree Surrenders												
25	Other												
26													
27													
28	Total												
29	Balance-End of Year	366	41,584	2,212								2,578	41,584
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												

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)
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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						
28						
20	TOTAL					

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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: Public Service Company of Oklahoma	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					
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20	Total				
21	**Generation Studies**				
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35					
36					
37					
38					
39	Total				
40	Grand Total				

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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	Deferred Debt, Unrecognized Equity Return, Depreciation Expense and Property Tax on NE Unit 3 and Comanche Environmental projects placed in service in 2016., OCC Cause No. PUD 201700151, Order No. 672864, Amortization Period: 03/2018 - 2040	23,875,249	702,910	182, 403, 408, 431	2,029,313	22,548,846
2	DRS Under Recovered Reg Asset	941	2,631,484			2,632,424
3	FERC Formula Rates Under Recvr	396,082		456	396,080	2
4	GRCF Regulatory Asset	179,885		407	179,885	
5	Independent Evaluator Deferral	109,851	115,695	182	96,469	129,078
6	Non-AMI Meters	18,131,021		407	4,034,095	14,096,926
7	Northeastern Power Plant Unit 4 Undepreciated balance to be amortized over 274 months, OCC Cause No. PUD 201700151, Amortization Period: 03/2018 - 2040	63,359,856		407	3,519,992	59,839,864
8	Oklaunion Undepreciated Balance	31,353,021		407	1,306,376	30,046,645
9	Retirement of Northeastern Power Plant Unit 4 Asbestos Asset Retirement Obligation (ARO) to be amortized over 274 months, Order No. 672864, Cause No. PUD 201700151, Amortization Period: 03/2018 - 2040	425,613		407, 506	23,743	401,870
10	PSO WFA RIDER O/U - TRUE UP	4,925,085	5,966,161	403	5,296,735	5,594,511
11	Rate Case Expenses approved for recovery in to be amortized over two years, OCC Final Order No. 672864, Cause No. PUD 202100055, Amortization Period: 11/2021 - 2023	396,115	852,251	928	688,692	559,674
12	SFAS 106 Medicare Subsidy, Amortization Period: 01/2013 - 12/2024	979,830		926	489,915	489,914
13	SFAS 109 Deferred FIT	11,253,964	7,199,386	282, 283	4,578,611	13,874,740
14	SFAS 109 Deferred SIT	1,953,721	2,489,606	283	2,615	4,440,712
15	SFAS 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	55,208,423	67,432,150	129, 228	60,015,309	62,625,264
16	Terminated Red Rock Generating Facility Pre Construction Costs, OCC Cause No. PUD 200700465 Order No. 554328, Amortization Period: 02/2009 - 2057	7,696,020		506	225,800	7,470,220
17	The Refund for protected Excess DFIT Over/under recovery, PUD Orders No.671981 and No.680821	8,731,025	1,038,028	407	7,156,593	2,612,460
18	Under-recovery and related amortizations of Deferred Major/Minor Storm Restoration Expenses - Recovery, OCC Cause No. 201300217, Order No. 639314, OCC Cause No. 201700151, Order No. 672864	33,848,261	104,436,284	593	23,526,486	114,758,060
19	Under-recovery Fuel Cost - OK - Long Term	252,737,084		182	252,737,084	
20	Unrealized Loss on Forward Commitments	74,051	33,304,253	175, 244, 254	3,524,729	29,853,575
21	Unrecovered Fuel Cost – OK	178,731,656	253,102,417	182, 501	313,582,081	118,251,993
22	Windcatcher Cost Recovery AG	159,779	515,229	928	612,391	62,617
44	TOTAL	694,526,532	479,785,855		684,022,993	490,289,394

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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 Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Agency Fees - Factored Accounts Receivable	3,110,833	39,992,011	142/184/234/426	40,409,906	2,692,938
2	Deferred Billings on Associated Business Development	154,292	10,921,702	186/242/408/926	10,345,337	730,657
3	Unamortized Credit Line Fees Amortization period through 6/1/2022	711,535	522,245	146/234/431	401,915	831,865
4	Accrued Plant Retention and Severance Accrual related to Oklaunion.	(2,557)	79,029	152/183	72,366	4,106
5	Transource Missouri Formula Rate True-up Under-recovery	294,509	4,869,502	146/158/232/509/565	5,081,560	82,451
6	Deferred Lease Expense	41,666	672,451	143/184/242	467,184	246,933
7	Minor Items	(194,489)	96,486	131/142/146/184/186/232/234/235/242/253	(110,946)	12,943
8	PSO WV WY MO 2021 RR	835	10,314	151/236	11,150	
9	SPP 2022 TRUE-UP ESTIMATE	6,693,455	5,936,950	146/234/253/565	6,598,603	6,031,802
10	BPF TRUE UP	526,908	23,656,600	146/234/253/565	1,318,346	22,865,162
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	11,336,987				33,498,857

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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	EXCESS ADFIT 282 - PROTECTED OK	94,705,685	87,324,068
3	TAX CREDIT C/F - DEF TAX ASSET	54,329,028	53,831,110
4	ADSITC STATE C/F-DEF STATE TAX ASSET LT	39,252,953	39,723,083
5	BOOK OPERATING LEASE - LIAB	21,815,504	23,566,328
6	PSO-FUEL O/U RECOVERY WSLE	(87,002,219)	(23,843,177)
7	Other	3,978,573	11,420,541
8	TOTAL Electric (Enter Total of lines 2 thru 7)	127,079,524	192,021,953
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	[a] 97,880,760	90,344,520
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	224,960,284	282,366,473

Notes

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Notes

Page 234, Line 17, Columns B & C	Beginning of Year	End of Year
Acc Def Income Taxes - Federal - Hdg-CF-Int Rate	—	212,319
Non-Utility - 190.2	524,446	—
SFAS 109 - Regulatory Assets - 190.3, 190.4 & 190.6	97,356,314	90,132,201
SFAS 133	—	—
Accu Def Income Taxes Pension-OCI	—	—
Total Line 17	$97,880,760	$90,344,520
Line 18		
Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :		
Balance at Beginning of Year		$224,960,284
(Less) Amounts Debited to:		
(a) Account 410.1		(60,149,806)
(b) Account 410.2		(2,141,932)
(c) 1823/254/219/129/427		(10,531,314)
(Plus) Amounts Credited to:		
(a) Account 411.1		124,482,024
(b) Account 411.2		1,617,486
(c) 1823/254/219/129/427		4,129,731
Balance at End of Year		$282,366,473

Name of Respondent: Public Service Company of Oklahoma	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	Common Stock (Account 201)	11,000,000	15.00		10,482,000	157,230,000				
7	Total	11,000,000			10,482,000	157,230,000				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Public Service Company of Oklahoma	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	625,000,000
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	625,000,000
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	4,036,918
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	4,036,918
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	413,590,626
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	(3,342,000)
16	Ending Balance Amount	410,248,626
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	1,039,285,544

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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		
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20		
21		
22	TOTAL	

Name of Respondent: Public Service Company of Oklahoma	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	None										
3	Subtotal										
4	Reacquired Bonds (Account 222)										
5	None										
6	Subtotal										
7	Advances from Associated Companies (Account 223)										
8	None										
9	Subtotal										
10	Other Long Term Debt (Account 224)										
11	Senior Unsecured Notes, Series G - 6.25%		250,000,000		2,364,345		1,867,500	11/14/2007	11/15/2037	11/14/2007	11/15/2037
12	Senior Unsecured Notes, Series C - 3.05%		50,000,000		177,485			07/19/2016	08/01/2026	07/19/2016	08/01/2026
13	Senior Unsecured Notes, Series D - 4.11%		100,000,000		355,362			07/19/2016	08/01/2046	07/19/2016	08/01/2046
14	Senior Unsecured - Series L - 5.25%		475,000,000		3,937,658		1,472,500	01/05/2023	01/18/2033	01/05/2023	01/18/2033
15	Senior Unsecured Notes, Series A - 3.17% (Oklahoma Corporation Commission Authority: Order No. 631653		125,000,000		607,973			01/29/2015	03/31/2025	01/29/2015	03/31/2025
16	Senior Unsecured Notes, Series B - 4.09% (Oklahoma Corporation Commission Authority: Order No. 631653		125,000,000		607,973			01/29/2015	03/31/2045	01/29/2015	03/31/2045
17	Senior Unsecured Notes, Series E - 3.91%		100,000,000		928,420			03/07/2019	03/15/2029	03/07/2019	03/15/2029
18	Senior Unsecured - Series F - 4.11%		150,000,000		2,581,779			06/01/2019	06/01/2034	06/01/2019	06/01/2034
19	Senior Unsecured - Series G - 4.50%		100,000,000		623,944			06/01/2019	06/01/2049	06/01/2019	06/01/2049
20	Senior Unsecured - Series K - 3.15%		400,000,000		3,763,812		1,696,000	08/13/2021	08/15/2051	08/13/2021	08/15/2051
21	Senior Unsecured - Series J -2.20%		400,000,000		3,763,812		1,320,000	08/13/2021	08/15/2031	08/13/2021	08/15/2031
22	Foreign Exchange Hedges										
23	gridSMART Loan Agreement Promissory Note, 3.00% State Energy Program American Recovery and Reinvestment Act of 2009Revolving Loan Program Promissory Note - Fixed Rate 14207 SSEP 09		7,375,827					06/01/2010	06/01/2027	06/01/2012	06/01/2027
24	Oklahoma Local Revolving Credit Facility, Variable Rate		125,000,000					11/04/2019	09/30/2025	11/04/2019	09/30/2025
25	Revolving Credit Facility - 0.96%										
26	Revolving Credit Facility - 0.960%										
27	Initial Draw Credit Facility										

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)
28	Subtotal		2,407,375,827		19,712,563		6,356,000				
33	TOTAL		2,407,375,827								

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	250,000,000	16,562,500
12	50,000,000	1,525,000
13	100,000,000	4,110,000
14	475,000,000	24,660,417
15	125,000,000	3,962,500
16	125,000,000	5,112,500
17	100,000,000	3,910,000
18	150,000,000	6,384,583
19	100,000,000	4,500,000
20	400,000,000	12,600,000
21	400,000,000	8,580,417
22		32,312
23	1,982,564	66,982
24	125,000,000	8,092,742
25		
26		
27		
28	2,401,982,564	100,099,953
33	2,401,982,564	100,099,953

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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)	208,852,129
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	Reconciling Items for the Year	
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]32,562,653
28	Show Computation of Tax:	
29		
30		
31		
32		
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Line No.	Particulars (Details) (a)	Amount (b)
43		
44		
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FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

		(000's)
Net Income for the year per Page 117		208,852
Federal and State Income Taxes		(53,582)
Pretax Book Income		155,270
Increase (Decrease) in Taxable Income resulting from:		
Allowance for Funds Used During Construction and Other Differences Between Items Capitalized for Books and Expensed for Tax		(5,628)
Book/Tax Unit of Property Adj		(134,900)
Capitalized Relocation Costs		(8,573)
Deferred Fuel Costs (Net)		313,217
Demand Side Management Expenses		—
Deferred Storm Damages		(80,586)
Excess Tax Vs Book Depreciation		(188,925)
Pollution Control		2,739
Pension Expenses (Net)		5,819
Provision for Revenue Refunds		15,963
Regulatory Assets		5,986
Removal Costs		(44,923)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)		(4,399)
SFAS 112 - Post Employment Benefit Expense Accrued/Funded (Net)		(1,905)
Capitalized Software		9,430
Book/Tax Unit of Property Adj		
Book Impaired Asset		—
Other (Net)		(5,747)
		9,422
Less: Current Year Current State Income Tax Accrual		274
	0	
Federal Tax Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		6,838
Computation of Tax *		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 21%		6,838
Adjustment due to System Consolidation		—
Estimated Tax Currently Payable	(a)	6,838
Tax Credit Carryforward		172
R & D Credit		26
Electric production credit		64,294
NOL Deferred Tax Asset		—
		(57,654)
Adjustments of Prior Year's Accruals (Net)		(3,163)
Estimated Current Federal Income Taxes on Current Taxable Income(Net)		(60,817)

(a) Represents the allocation of the estimated current year net operating tax loss of American Electric Power Company, Inc.

INSTRUCTION 2.

* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal income tax. The computation of actual 2022 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by October 2023. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated Federal income tax return is filed.

Name of Respondent: Public Service Company of Oklahoma	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 Taxes	Federal Tax			(16,097,094)	0	(22,234,252)	(7,285,270)		(31,046,076)	0
2					0	0				0	0
3	**Subtotal Federal Tax**				(16,097,094)	0	(22,234,252)	(7,285,270)	0	(31,046,076)	0
4	State Tax	State Tax	Multi	19	3,163					3,163	
5	State Tax	State Tax	OK	17	(372,740)	0				(372,740)	0
6	State Tax	State Tax	OK	18	(213,986)	0				(213,986)	0
7	State Tax	State Tax	OK	19	2,935,570	0				2,935,570	0
8	State Tax	State Tax	OK	20	(2,568,247)	0				(2,568,247)	0
9	State Tax	State Tax	OK	21	219,400	0				219,400	0
10	State Tax	State Tax	OK	22	0	0				0	
11	State Tax	State Tax	OK	23		0	273,776			273,776	
12	State Tax	State Tax	TX	18	(1,041)	0				(1,041)	0
13	State Tax	State Tax	TX	19	849	0				849	0
14	State Tax	State Tax	TX	20	2,401	0				2,401	0
15	State Tax	State Tax	TX	21	16,223	0				16,223	0
16	State Tax	State Tax	TX	22	(18,431)					(18,431)	
17	**Subtotal State Tax**				3,161	0	273,776	0	0	276,937	0
18	Local Taxes	Local Tax	OK	19	(3,163)	0				(3,163)	0
19	Local Taxes	Local Tax	OK	22	494,618		(32,427)	462,191			
20	Local Taxes	Local Tax	OK	23		0	7,889,958	7,228,669		661,289	0
21	**Subtotal Local Tax**				491,455	0	7,857,531	7,690,860	0	658,126	0
22	**Subtotal Other Tax**				0	0	0	0	0	0	0
23	Pers Prop Leased	Property Tax	OK	22	79,842	0	0	79,842		0	0
24	Pers Prop Leased	Property Tax	OK	23		0	145,780	72,932		72,848	0
25	Pers Prop Leased	Property Tax	TX	22		0	256	256		0	0
26	Real & Pers Prop	Property Tax	AR	22		0	1,092	1,092		0	0
27	Real & Pers Prop	Property Tax	LA	23		0	571	571		0	0
28	Real & Pers Prop	Property Tax	MO	22	276	0	(42)	234		0	0
29	Real & Pers Prop	Property Tax	MO	23			7,500	7,500		0	
30	Real & Pers Prop	Property Tax	OK	18		0				0	0
31	Real & Pers Prop	Property Tax	OK	22	26,047,540	0	14,880	26,062,422		(2)	0
32	Real & Pers Prop	Property Tax	OK	23		0	56,095,239	28,217,878		27,877,361	0
33	Real & Pers Prop	Property Tax	TX	22	632,225	0	(227)	631,998		0	0
34	Real & Pers Prop	Property Tax	TX	23			700,658	1,570		699,088	
35	Real & Pers Prop	Property Tax	WV	22			15	15		0	
36	Real & Pers Prop	Property Tax	WY	21	42	0	(276)	(234)		0	0
37	Real & Pers Prop	Property Tax	WY	22		0	834	834		0	0
38	Real & Pers Prop	Property Tax	MS	22		0	0	0		0	0
39	Pers Prop Leased	Property Tax	OK	19			537	537		0	
40	**Subtotal Property Tax**				26,759,925	0	56,966,817	55,077,447	0	28,649,295	0
41	**Subtotal Real Estate Tax**				0	0	0	0	0	0	0
42	[a] UNEMPLOYMENT 2023	Unemployment Tax			3,556		57,121	48,627	0	12,050	

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)
43	STATE UNEMPLOYMENT 2023	Unemployment Tax	OK		14,929		203,017	203,468	0	14,477	
44	STATE UNEMPLOYMENT 2023	Unemployment Tax	TX		0		1,043	1,043	0	0	
45	**Subtotal Unemployment Tax**				18,485	0	261,181	253,138	0	26,527	0
46	Sales & Use Tax	Sales And Use Tax								0	
47	Sales & Use Tax	Sales And Use Tax	OK	22	701,422	2,727,633	(162,715)	(2,188,926)		0	
48	Sales & Use Tax	Sales And Use Tax	OK	23			11,917,241	14,503,936		599,891	3,186,586
49	Sales & Use Tax	Sales And Use Tax	TX	22			4,024	4,024		0	
50	Sales & Use Tax	Sales And Use Tax	TX	23			13,811	30		13,781	
51	**Subtotal Sales And Use Tax**				701,422	2,727,633	11,772,361	12,319,064	0	613,672	3,186,586
52	**Subtotal Income Tax**				0	0	0	0	0	0	0
53	Excise Tax	Excise Tax		23	0	0	1,380	1,380		0	
54	**Subtotal Excise Tax**				0	0	1,380	1,380	0	0	0
55	**Subtotal Fuel Tax**				0	0	0	0	0	0	0
56	FICA 2023	Federal Insurance Tax			770,904	0	9,099,462	9,370,571	0	499,795	
57	**Subtotal Federal Insurance Tax**				770,904	0	9,099,462	9,370,571	0	499,795	0
58	State Franchise	Franchise Tax	OK	22	0	0	20,000	20,000		0	
59	Franchise Tax	Franchise Tax	OK	23	0	0					
60	**Subtotal Franchise Tax**				0	0	20,000	20,000	0	0	0
61	Misc Taxes	Miscellaneous Other Tax	OK	23	0	0	480	480		0	
62	**Subtotal Miscellaneous Other Tax**				0	0	480	480	0	0	0
63	**Subtotal Other Federal Tax**				0	0	0	0	0	0	0
64	Other State Tax	Other State Tax	OH	22	0	0	1	1		0	
65	Other State Tax	Other State Tax	OH	23	0	0	5	5		0	
66	**Subtotal Other State Tax**				0	0	6	6	0	0	0
67	**Subtotal Other Property Tax**				0	0	0	0	0	0	0
68	**Subtotal Other Use Tax**				0	0	0	0	0	0	0
69	**Subtotal Other Advalorem Tax**				0	0	0	0	0	0	0
70	State License Registration	Other License And Fees Tax	WY	19	(52)	0	52		0	0	0
71	**Subtotal Other License And Fees Tax**				(52)	0	52	0	0	0	0
72	**Subtotal Payroll Tax**				0	0	0	0	0	0	0
73	**Subtotal Advalorem Tax**				0	0	0	0	0	0	0

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)
74	**Subtotal Other Allocated Tax**				0	0	0	0	0	0	0
75	**Subtotal Severance Tax**				0	0	0	0	0	0	0
76	**Subtotal Penalty Tax**				0	0	0	0	0	0	0
77	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0	0
40	TOTAL				12,648,206	2,727,633	64,018,794	77,447,676	0	(321,723)	3,186,586

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	(64,100,713)			41,866,461
2				
3	(64,100,713)	0	0	41,866,461
4				
5				
6				
7				
8				
9				
10				
11	(1,007,018)			1,280,794
12				
13				
14				
15				
16				
17	(1,007,018)	0	0	1,280,794
18				
19	(1,154)			(31,273)
20	7,866,608			23,350
21	7,865,454	0	0	(7,923)
22	0	0	0	0
23	0			
24	145,748			32
25	256			0
26				1,092
27				571
28				(42)
29				7,500
30	190,505			(190,505)
31	32,446			(17,566)
32	50,080,657			6,014,581
33	(227)			
34	695,758			4,900
35				15
36				(276)
37				834
38				0
39	537			
40	51,145,680	0	0	5,821,136
41	0	0	0	0
42	34,996			22,125
43	111,811			91,206
44	582			460
45	147,389	0	0	113,791
46	0			
47	1,730			(164,445)
48	911,519			11,005,722

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)
49	2,823			1,202
50	(949,969)			963,780
51	(33,897)	0	0	11,806,259
52	0	0	0	0
53	1,380			
54	1,380	0	0	0
55	0	0	0	0
56	5,005,788			4,093,674
57	5,005,788	0	0	4,093,674
58	20,000			
59				
60	20,000	0	0	0
61	480			
62	480	0	0	0
63	0	0	0	0
64	1			
65	5			
66	6	0	0	0
67	0	0	0	0
68	0	0	0	0
69	0	0	0	0
70	52			
71	52	0	0	0
72	0	0	0	0
73	0	0	0	0
74	0	0	0	0
75	0	0	0	0
76	0	0	0	0
77	0	0	0	0
40	(955,399)	0	0	64,974,192

Name of Respondent: Public Service Company of Oklahoma	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: DescriptionOfTaxesAccruedPrepaidAndCharged
Consists of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purposes of reporting all prepaid tax activity.

Name of Respondent: Public Service Company of Oklahoma	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 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					
3	4%	227			411.4			227		
4	7%				411.4					
5	10%	5,236,420	411		411.4	1,372,207		3,864,213		
6	State DITC	42,934,656	411.1		411.4	(387,722)		43,322,378		
7	30	1			411.4			1		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	48,171,303				984,485		47,186,819		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	48,171,303						47,186,819		

Name of Respondent: Public Service Company of Oklahoma	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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Pole Attachments	923,818	108/142/143/154/184/186/241/421/454/456	1,958,670	2,069,706	1,034,854
2	Customer and Other Advance Receipts	9,327,472	142/253	9,327,472	8,343,237	8,343,237
3	PowerPay Prepaid Paymt Program	1,408,599	142/253	1,408,600	1,271,441	1,271,441
4	TRE (Texas Reliability Entity) Audit Penalty (Long Term)	353,898	242/426	38,807		315,091
5	Contributions in Aid of Construction	999,779	107/108	999,779	1,282,346	1,282,345
6	Deferred Revenue - Oil and Gas Lease Bonus Payment Agreement					
7	Minor Items	1,462,055	107/131/134/142/143/146/184/186/232/234/235/242/557	1,472,690	526,624	515,989
8	Associated Business Development					
9	Environmental Liabilities	150,000				150,000
10	O\U Accounting of ExpensesT	5,366	565/234	6,852	12,737	11,251
11	Long Term Assoc AP	2,299,478	234/253/449/456	2,671,314	12,518,263	12,146,427
47	TOTAL	16,930,465		17,884,183	26,024,353	25,070,635

Name of Respondent: Public Service Company of Oklahoma	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	22,763,740	637,224	1,510,802							21,890,162
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	22,763,740	637,224	1,510,802							21,890,162
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	[a] Other - SFAS 109	(7,397,021)					254		254	301,389	(7,095,632)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	15,366,719	637,224	1,510,802						301,389	14,794,530
18	Classification of TOTAL										
19	Federal Income Tax	15,366,719	637,224	1,510,802						301,389	14,794,530
20	State Income Tax										
21	Local Income Tax										

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Name of Respondent: Public Service Company of Oklahoma	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: DescriptionOfAcceleratedAmortizationPropertyOtherUtilityOther

Description Page 272-273 Line 16	Balance at Beginning of The year	Amounts Debited to Account 410.2	Amounts Credits to Account 411.2	Debit Adjust.	Credit Adjust.	Balance End of Year
SFAS 109	(8,004,798)				607,777	(7,397,021)
Total Line 16	(8,004,798)	—	—		607,777	(7,397,021)

Name of Respondent: Public Service Company of Oklahoma	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 - 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				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			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)	
1	Account 282										
2	Electric	1,046,640,345	138,901,144	83,339,705					190	(49,542)	1,102,152,242
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,046,640,345	138,901,144	83,339,705						(49,542)	1,102,152,242
6	[(a)] Other	(285,098,116)					1823/254	536,754	1823/254	30,166,398	(255,468,472)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	761,542,229	138,901,144	83,339,705				536,754		30,116,856	846,683,770
10	Classification of TOTAL										
11	Federal Income Tax	761,542,229	138,901,144	83,339,705				536,754		30,116,856	846,683,770
12	State Income Tax										
13	Local Income Tax										

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Name of Respondent: Public Service Company of Oklahoma	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: DescriptionOfNonUtilityAccountDetails

Line 6 Footnote

	Beg Bal	Debits	Credits	End Bal
Non-Utility	—	—	—	—
SFAS 109	(285,098,116)	536,754	30,166,398	(255,468,472)
Total Other - Line 6	(285,098,116)	536,754	30,166,398	(255,468,472)

Name of Respondent: Public Service Company of Oklahoma	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 - 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			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)	
1	Account 283										
2	Electric										
3	ACRS BENEFIT NORMALIZED	67,753,464	11,204,681	3,785,018							75,173,127
4	PSO-FUEL O/U RECOVERY-WSLE	17,172,456	24,162	12,483,567							4,713,051
5	BOOK/TAX UNIT OF PROPERTY ADJ	21,661,634	11,686,525	5,505,661							27,842,498
6	LIBERALIZED DEPR-ELIG DFL	21,164,350	29,779								21,194,129
7	EXCESS DSIT - UNPROTECTED OK	38,929,015									38,929,015
8	REG ASSET	57,365,810	3,698,374	1,712,964							59,351,220
9	Other	53,896,959	48,082,115	34,036,711			—	137,335	283		67,805,028
9	TOTAL Electric (Total of lines 3 thru 8)	277,943,688	74,725,636	57,523,921				137,335			295,008,068
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[a](41,281,246)					1823/254	9,519,037	1823/254	7,938,503	(42,861,780)
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	236,662,442	74,725,636	57,523,921				9,656,372		7,938,503	252,146,288
20	Classification of TOTAL										
21	Federal Income Tax	69,242,536	35,696,382	24,544,572	307,517	(2,074,108)		7,386,573		3,319,047	78,708,445
22	State Income Tax	167,419,906	39,029,254	32,979,349	(307,517)	2,074,108		2,269,799		4,619,456	173,437,843
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line 18 Footnote

	Beg Bal	Debits	Credits	End Bal
Provision optimization	338,625	—	543,442	543,442
Hedge - Cash Flow		187,928	—	150,697
Non-Utility	—	—	—	—
SFAS 109	(41,619,871)	9,331,109	7,395,061	(43,555,919)
	(41,281,246)	9,519,037	7,938,503	(42,861,780)

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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	Energy Efficiency O/U Recovery	4,101,018	440, 442, 444, 908	13,564,940	9,601,958	138,035
2	Over-Recovered PSO BPF	8,897,722	565	6,336,460	1,257,905	3,819,167
3	PSO's OK Veg Mgmnt O/U Recovery To track the over funded balance for Oklahoma's System Reliability Rider (SRR) in accordance with PSO's Final Order No. PUD 201500208, Order No. 644241. Disposition of Balance should be determined within one year.	213,615	593	213,615		
4	SFAS 109 Deferred Federal Income Tax	393,359,236	190, 182, 236, 254, 255, 281, 282, 283, 409, 410, 411	39,199,070	8,544,295	362,704,461
5	SFAS 109 Deferred State Income Tax	51,319,761				51,319,761
6	Unrealized Gain/Loss on Forward Commitments	8,270	175, 182	1,784,546	1,776,276	
7	LSE Formula Rate Deferral				1,240,551	1,240,551
41	TOTAL	457,899,623		61,098,631	22,420,984	419,221,976

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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	839,605,658	815,819,947	6,138,285	6,618,174	494,201	491,335
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	544,449,660	488,822,860	5,190,452	5,152,894	66,889	66,519
5	Large (or Ind.) (See Instr. 4)	427,224,725	372,384,964	5,931,873	6,073,176	6,193	6,400
6	(444) Public Street and Highway Lighting	4,770,993	4,245,725	41,918	42,392	373	359
7	(445) Other Sales to Public Authorities	109,182,446	98,614,840	1,212,669	1,254,128	8,190	8,121
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,925,233,483	1,779,888,337	18,515,197	19,140,765	575,846	572,734
11	(447) Sales for Resale	20,052,153	42,655,681	466,253	622,139		1
12	TOTAL Sales of Electricity	1,945,285,636	1,822,544,017	18,981,450	19,762,904	575,846	572,735
13	(Less) (449.1) Provision for Rate Refunds	37,557,066	3,962,384				
14	TOTAL Revenues Before Prov. for Refunds	1,907,728,570	1,818,581,633	18,981,450	19,762,904	575,846	572,735
15	Other Operating Revenues						
16	(450) Forfeited Discounts	3,101,534	2,840,471				
17	(451) Miscellaneous Service Revenues	425,046	422,604				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	5,493,432	7,175,744				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	16,968,682	19,920,937				
22	(456.1) Revenues from Transmission of Electricity of Others	56,296,708	43,116,477				
23	(457.1) Regional Control Service Revenues						

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)
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	82,285,402	73,476,233				
27	TOTAL Electric Operating Revenues	1,990,013,972	1,892,057,867				

Line12, column (b) includes $ (5,695,780) of unbilled revenues.
Line12, column (d) includes (125,346) MWH relating to unbilled revenues

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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					
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41					
42					

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)
43					
44					
45					
46	TOTAL				
Page 302					

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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	[(a)] RS Cogen 062					
2	LURS 020	8,000	1,648,267	4,922	1,625	0.2100
3	LUGS 264	23	5,045	1	23,389	0.2200
4	RS 015	5,875,028	818,613,036	467,344	12,571	0.1400
5	RS 038	1,602	208,582	270	5,926	0.1300
6	RS TOD2TR 028	278,037	37,777,238	19,202	14,480	0.1400
7	RS PEV 029	5,095	650,493	251	20,278	0.1300
8	RS GOGEN Distributive Generation CR 064	157	16,290	11	14,478	0.1000
9	RS Net Meter 067	28,080	2,488,971	2,200	12,764	0.0900
10	Non-Roadway Lght 151-163	42	14,144	94	449	0.3400
11	LED Light 170-186	1,796	813,829	6,352	283	0.4500
12	Sec Lght 093-145	16,507	5,602,194	26,125	632	0.3400
13	Deferred EE		695,057			
14	PSO Securitization		(25,048,715)	(32,571)		
41	TOTAL Billed Residential Sales	6,214,367	843,484,431	494,201		
42	TOTAL Unbilled Rev. (See Instr. 6)	(76,082)	(3,878,773)			
43	TOTAL	6,138,285	839,605,658	494,201	12,421	0.1368

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FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule
Revenue Accounts 440, 442, 444, and 445 have a uniform standard fuel adjustment clause applicable to the rate schedule shown and the aggregate estimated revenue billed pursuant thereto is 788652287.427

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	GS 212 213	7,043	693,786	890	7,909	0.1000
2	GS 254	1,671,841	191,335,027	6,710	249,147	0.1100
3	GS 252	51,279	5,510,938	50	1,018,782	0.1100
4	LPL 242	158,858	9,217,797	3	47,657,365	0.0600
5	LPL 244	283,847	18,771,943	8	37,430,339	0.0700
6	LPL 246	843,365	67,990,872	184	4,573,148	0.0800
7	LPL 248	55,228	5,313,043	20	2,784,615	0.1000
8	LPL 250	859,018	86,056,423	1,348	637,017	0.1000
9	LUGS 262	1,590	198,301	63	25,407	0.1200
10	LUGS 264	836,653	112,643,654	46,525	17,983	0.1300
11	LUGS 266	176	32,845	104	1,695	0.1900
12	MOL 204	1,954	266,124	539	3,624	0.1400
13	MOL 214	3,269	357,072	602	5,433	0.1100
14	RS 015	14	1,549	2	7,141	0.1100
15	Sec Lght 093-145	31,160	8,032,809	12,560	2,481	0.2600
16	Non-Roadway Lght 151-163	253	49,545	106	2,389	0.2000
17	LED Light 170-186	3,638	1,495,769	2,822	1,290	0.4100
18	Traffic Signal 202	33	4,047	6	5,469	0.1200
19	Traffic Signal 203	3	481	1	2,341	0.1500
20	Outdoor Lght 207	371	42,362	30	12,231	0.1100
21	Recreational Lght 208	255	26,351	1	255,280	0.1000
22	Recreational Lght 209	18	2,888	1	17,520	0.1600
23	GS-UMSMTRD	6,586	711,921	1,034	6,367	0.1100
24	GS Plug In Electric Vehicle	664	84,093	1	1,328,400	0.1300
25	PL-TOD 249	493	45,352	1	492,732	0.0900
26	GS-Net Meter TOD 257	10,265	1,044,977	20	504,857	0.1000
27	GS-TOD 259	68,179	7,701,093	226	301,679	0.1100
28	LUGS<100H	2,546	1,957,775	5,828	437	0.7700
29	LUGS Net Meter TOD 269	770	74,520	30	25,809	0.1000
30	LUGS TOD 269	21,010	2,215,307	395	53,245	0.1100
31	LPL PRI 296	13	25,597	1	13,000	1.9700
32	PRSV NOND	6,706	727,800	17	394,452	0.1100
33	GS PSF 304	268,285	29,865,478	811	330,739	0.1100
34	LUGS PSF 314	30,818	3,598,883	1,437	21,446	0.1200
35	Deferred EE		607,326			
36	Other					
37	PSO Securitization		(10,954,530)	(15,487)		
41	TOTAL Billed Small or Commercial	5,226,201	545,749,218	66,889		

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)
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(35,749)	(1,299,558)			
43	TOTAL Small or Commercial	5,190,452	544,449,660	66,889	77,598	0.1000
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	GS 254	374,633	43,271,623	996	376,200	0.1200
2	GS 252	1,332	152,630	4	319,591	0.1100
3	LPL 242	909,759	53,809,778	12	75,813,248	0.0600
4	LPL 244	3,322,344	215,898,869	42	78,019,831	0.0700
5	LPL 246	957,171	81,126,474	219	4,372,309	0.0800
6	LPL 248	25,474	2,464,461	5	5,094,720	0.1000
7	LPL 250	209,036	20,901,549	153	1,368,484	0.1000
8	LUGS 262	71	9,439	5	13,794	0.1300
9	LUGS 264	84,924	10,946,867	4,081	20,810	0.1300
10	MOL 204	4	603	2	2,761	0.1500
11	MOL 214	85	8,766	3	28,184	0.1000
12	Non-Roadway Lght 151-163	34	6,186	8	4,192	0.1800
13	LED Light 170-185	539	210,762	241	2,242	0.3900
14	Sec Lght 093-145	3,474	761,882	1,014	3,425	0.2200
15	GS NEBO TOD 257	188	23,529	1	132,678	0.1300
16	GS TOD 259	15,224	1,710,137	36	423,868	0.1100
17	LUGS<100H	185	177,234	546	339	0.9600
18	LUGS NEBO TOD 263	1	278		2,823	0.3000
19	LUGS TOD 269	3,130	324,448	55	56,994	0.1000
20	LPL SUPPL 292	5,156	566,068	1	5,155,867	0.1100
21	PRSV NOND	15,199	1,650,336	21	720,895	0.1100
22	STNBY TRN 392	11,510	2,099,776	11	1,046,363	0.1800
23	PSO Securitization		(8,764,579)	(1,263)		
24	Deferred EE		165,777			
41	TOTAL Billed Large (or Ind.) Sales	5,939,473	427,522,893	6,193		
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(7,600)	(298,168)			
43	TOTAL Large (or Ind.)	5,931,873	427,224,725	6,193	957,796	0.0700

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Name of Respondent: Public Service Company of Oklahoma	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

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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	GSL 533	13	1,417	1	13,068	0.1100
2	GSL 532	330	43,915	2	164,910	0.1300
3	MSL 529	130	8,774	4	32,640	0.0700
4	MSL 531	39,733	4,313,241	190	209,211	0.1100
5	MSL 534	441	58,478	35	12,558	0.1300
6	MSL 535	1,272	360,634	141	9,011	0.2800
7	Deferred EE		81,368			
8	PSO Securitization		(96,786)			
41	TOTAL Billed Public Street and Highway Lighting	41,919	4,771,041	373		
42	TOTAL Unbilled Rev. (See Instr. 6)	(1)	(48)			
43	TOTAL	41,918	4,770,993	373	112,307	0.1100

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	GS 212-213	2,966	342,216	884	3,355	0.1200
2	GS 254	258,536	28,583,988	768	336,453	0.1100
3	GS 252	18,632	2,008,128	7	2,661,791	0.1100
4	LPL 242	73,624	4,751,875	5	14,483,363	0.0600
5	LPL 244	299,311	20,944,613	9	32,652,102	0.0700
6	LPL 246	269,961	22,512,984	43	6,339,603	0.0800
7	LPL 248	3,365	306,792	2	1,682,610	0.0900
8	LPL 250	178,012	17,250,050	166	1,072,362	0.1000
9	LUGS 262	43	10,046	11	3,897	0.2400
10	LUGS 264	80,492	10,565,661	4,464	18,028	0.1300
11	MOL 204	853	100,447	113	7,562	0.1200
12	MOL 214	1,531	161,740	100	15,309	0.1100
13	MP 540	9,009	862,781	59	151,629	0.1000
14	MSL 218	7,930	828,811	23	338,659	0.1000
15	Non-Roadway Lght 151-163	17	4,096	9	1,951	0.2400
16	LED Light 170-184	334	139,766	225	1,484	0.4200
17	Sec Lght 093-145	3,403	956,381	1,214	2,803	0.2800
18	LED TS 201	335	45,715	104	3,224	0.1400
19	LED TS 202	961	118,460	187	5,150	0.1200
20	LED TS 203	308	39,257	74	4,188	0.1300
21	GSMTRMSC	18	1,968	1	17,767	0.1100
22	GSMTRMSCL	444	48,150	14	31,932	0.1100
23	MOL 207	666	70,924	5	133,172	0.1100
24	MOL 210	34	6,854	29	1,177	0.2000
25	MOL 217	6	620	1	5,712	0.1100
26	MSL 219	14	1,342	1	24,000	0.1000
27	GS NEBO TOD 257	342	40,641	2	170,880	0.1200
28	GS TOD 259	1,132	131,375	3	377,287	0.1200
29	LUGS<100H	326	349,410	1,098	297	1.0700
30	LUGS NEBO TOD 263	9	748	1	9,098	0.0800
31	LUGS TOD 269	120	15,826	4	27,728	0.1300
32	PRSV NOND	5,849	595,403	12	471,028	0.1000
33	Other		(2,395,389)	(1,448)		
41	TOTAL Billed Other Sales to Public Authorities	1,218,583	109,401,679	8,190		
42	TOTAL Unbilled Rev. (See Instr. 6)	(5,914)	(219,233)			
43	TOTAL	1,212,669	109,182,446	8,190	148,053	0.0900

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Name of Respondent: Public Service Company of Oklahoma	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						
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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)
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		37,557,066			
Page 304						

Name of Respondent: Public Service Company of Oklahoma	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)
41	TOTAL Billed - All Accounts	18,640,543	1,930,929,262	575,846		
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(125,346)	(5,695,780)			
43	TOTAL - All Accounts	18,515,197	1,925,233,482	575,846		

Name of Respondent: Public Service Company of Oklahoma	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) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Requirement Service (RQ)										
2	[(a)] Town of South Coffeyville (1)	RQ	234	1.5	0.9	1.5	8,119		302,382	186,852	489,234
3	Wholesale Over/Under (2)	RQ									
4	Non-Requirement Service (non-RQ)										
5	American Electric Power Service										
6	Corporation (AEPSC) (3,4)	OS	228				0		32,799		32,799
7	AEPSC (3,5)	OS	228								
8	Electric Reliability										
9	Council of Texas (ERCOT) (6)	OS									
10	Southwest Power Pool (7)	OS					458,134		11,654,343	7,875,777	19,530,120

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 Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
15	Subtotal - RQ						8,119		302,382	186,852	489,234
16	Subtotal-Non-RQ						458,134		11,687,142	7,875,777	19,562,919
17	Total						466,253		11,989,524	8,062,629	20,052,153
Page 310-311											

Name of Respondent: Public Service Company of Oklahoma	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: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Includes customer charges

2 Wholesale Over/Under Recovery Calculation

3 Respondent is an affiliate company of American Electric Power Company, Inc. (AEP)

4 Bookout Margin Net

5 Realization System Integration Agreement Sharing

6 Net Trading Purchases & Sales within ERCOT

7 Net Trading Purchases & Sales within Southwest Power Pool (SPP)

Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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	15,060,419	16,544,909
5	(501) Fuel	500,255,858	129,840,662
6	(502) Steam Expenses	9,277,123	9,757,629
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,569,090	5,483,031
10	(506) Miscellaneous Steam Power Expenses	7,662,922	7,253,135
11	(507) Rents		2,531
12	(509) Allowances	2,289,742	515,973
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	540,115,153	169,397,870
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,722,643	3,114,088
16	(511) Maintenance of Structures	3,110,793	4,103,839
17	(512) Maintenance of Boiler Plant	15,242,648	12,098,871
18	(513) Maintenance of Electric Plant	10,024,847	9,072,431
19	(514) Maintenance of Miscellaneous Steam Plant	2,389,716	2,145,979
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	33,490,647	30,535,208
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	573,605,800	199,933,078
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		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
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		
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	2,246,658	1,406,984
63	(547) Fuel	13,247,910	22,853,449
64	(548) Generation Expenses	380,364	312,949
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	2,023,120	976,548
66	(550) Rents	5,395,941	4,089,058
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	23,293,993	29,638,988
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	26,226	2,395
71	(553) Maintenance of Generating and Electric Plant	8,263,920	6,320,797
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	123,192	197,387
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	8,413,338	6,520,579
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	31,707,331	36,159,567
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	452,489,818	754,763,953
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	726,337	625,065
78	(557) Other Expenses	2,675,825	2,698,379
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	455,891,979	758,087,397
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,061,205,110	994,180,042
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,127,645	6,105,929
85	(561.1) Load Dispatch-Reliability		62
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	339,571	301,354
87	(561.3) Load Dispatch-Transmission Service and Scheduling	(2,872)	(5,307)
88	(561.4) Scheduling, System Control and Dispatch Services	5,946,412	5,203,916
89	(561.5) Reliability, Planning and Standards Development	111,577	117,360
90	(561.6) Transmission Service Studies	(10)	
91	(561.7) Generation Interconnection Studies		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
92	(561.8) Reliability, Planning and Standards Development Services	1,265,686	1,039,997
93	(562) Station Expenses	772,642	585,136
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	82,054	58,480
95	(564) Underground Lines Expenses	472	
96	(565) Transmission of Electricity by Others	143,994,443	170,743,688
97	(566) Miscellaneous Transmission Expenses	2,694,143	2,904,128
98	(567) Rents	2,129,799	43,567
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	162,461,561	187,098,310
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	119,283	42,673
102	(569) Maintenance of Structures	12,079	32,438
103	(569.1) Maintenance of Computer Hardware	5,192	5,661
104	(569.2) Maintenance of Computer Software	494,765	416,674
105	(569.3) Maintenance of Communication Equipment	117,040	93,562
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	939,442	1,213,452
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	4,162,393	5,112,693
109	(572) Maintenance of Underground Lines	89	14
110	(573) Maintenance of Miscellaneous Transmission Plant	916,275	686,783
111	TOTAL Maintenance (Total of Lines 101 thru 110)	6,766,557	7,603,950
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	169,228,118	194,702,260
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	1,847,774	1,865,999
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,847,774	1,865,999
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)	1,847,774	1,865,999
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,591,726	3,448,164
135	(581) Load Dispatching	2,288,633	2,320,346
136	(582) Station Expenses	1,226,034	1,453,101
137	(583) Overhead Line Expenses	2,887,174	2,137,452
138	(584) Underground Line Expenses	4,878,678	4,637,451
138.1	(584.1) Operation of Energy Storage Equipment		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
139	(585) Street Lighting and Signal System Expenses	32,822	510,802
140	(586) Meter Expenses	4,615,087	4,926,625
141	(587) Customer Installations Expenses	700,391	493,161
142	(588) Miscellaneous Expenses	9,341,936	8,821,694
143	(589) Rents	844,241	804,441
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	29,406,721	29,553,237
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	12,064	73,849
147	(591) Maintenance of Structures	53,214	124,545
148	(592) Maintenance of Station Equipment	1,415,780	2,674,073
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	53,725,316	57,693,154
150	(594) Maintenance of Underground Lines	1,354,441	845,481
151	(595) Maintenance of Line Transformers	148,532	67,842
152	(596) Maintenance of Street Lighting and Signal Systems	151,979	71,196
153	(597) Maintenance of Meters	397,839	328,335
154	(598) Maintenance of Miscellaneous Distribution Plant	151,304	139,869
155	TOTAL Maintenance (Total of Lines 146 thru 154)	57,410,469	62,018,344
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	86,817,190	91,571,581
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	866,390	924,684
160	(902) Meter Reading Expenses	191,991	192,989
161	(903) Customer Records and Collection Expenses	15,161,352	14,332,811
162	(904) Uncollectible Accounts	356,037	253,824
163	(905) Miscellaneous Customer Accounts Expenses	109,970	83,492
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	16,685,739	15,787,800
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	685,282	1,021,281
168	(908) Customer Assistance Expenses	31,387,894	37,042,737
169	(909) Informational and Instructional Expenses	10,017	25,688
170	(910) Miscellaneous Customer Service and Informational Expenses	15,046	29,648
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	32,098,239	38,119,354
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	102,730	111,846
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	102,730	111,846
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	24,789,938	25,023,898
182	(921) Office Supplies and Expenses	1,439,536	1,813,056
183	(Less) (922) Administrative Expenses Transferred-Credit	5,799,636	3,303,937
184	(923) Outside Services Employed	1,100,110	7,126,937
185	(924) Property Insurance	1,753,090	1,436,804
186	(925) Injuries and Damages	3,600,036	3,431,662
187	(926) Employee Pensions and Benefits	(3,979,715)	(297,025)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	4,130,458	3,364,279
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	166,763	391,563
192	(930.2) Miscellaneous General Expenses	4,707,778	4,791,954
193	(931) Rents	618,674	712,196
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	32,527,031	44,491,387
195	Maintenance		
196	(935) Maintenance of General Plant	6,099,869	7,859,356
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	38,626,901	52,350,743
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,406,611,802	1,388,689,625
Page 320-323			

Name of Respondent: Public Service Company of Oklahoma	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	American Electric Power									
2	McAlester Army Ammunitions Plant (6,7)	OS					5,686			
3	Green Country	OS								
4	[(a)] Service Corporation (AEPSC) (1,2)	OS								
5	AEPSC (1,3)	OS								
6	Minco (4)	OS					344,084			
7	Blue Canyon Wind Power LLC (4)	OS					312,320			
8	Oklahoma Gas and Electric Company(10)	EX							71,803	71,803
9	Covanta WBH, LLC (5)	OS					1,461			
10	Oklahoma Municipal Power Authority(11)	EX							587,198	587,198
11	Cowboy Wind (4)	OS					570,745			
12	Sleeping Bear Wind (4)	OS					181,525			
13	Department of Public Works -						77,635			
14	Southwest Power Pool (SPP) (5, 12)	OS					5,844,195			
15	Calpine (6)	SF								
16	Ft. Sill (6, 7)	OS					0			
17	Elk City Wind Farm (4)	OS					287,434			
18	Evergy Kansas Central (6)	SF								
19	Electric Reliability Council									
20	Goodwell (4)	OS					755,525			
21	Balko (4)	OS					654,007			
22	of Texas (ERCOT) (6, 8)	OS								
23	EXELON (6)	SF								
24	Seiling (4)	OS					720,271			
25	Calpine (5)	OS					928,380			
26	EXELON (5)	OS					0			
27	Evergy Kasnsas Central (5)	OS								
28	Grand River Dam Authority (9)	EX					0		88,115	88,115
29	WR (5)	OS								
30	Net Metering (13)	OS					165			
31	Purch Pwr-NonTrading-Nonassoc (WFEC)	OS								
32	Intercompany billing	OS								
33	Tenaska	SF								
34	Accounts Payable Accrual	OS								

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)
35	VAISALA	OS								
15	TOTAL						10,683,433	0	747,116	747,116

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1				
2	173,537	246,251		419,788
3	15,534,669			15,534,669
4				
5				
6		12,816,720		12,816,720
7		18,126,151		18,126,151
8				
9		31,916		31,916
10				
11		8,575,000		8,575,000
12		5,242,817		5,242,817
13		3,392,329		3,392,329
14		260,668,360		260,668,360
15	32,806,410			32,806,410
16	3,435,120			3,435,120
17		18,553,038		18,553,038
18				
19				
20		18,818,130		18,818,130
21		13,773,902		13,773,902
22		11,200		11,200
23				
24		18,230,744		18,230,744
25		24,725,250		24,725,250
26				
27				
28				
29				
30		75,078		75,078
31				0
32				
33	47,500			47,500
34		13,923		13,923
35		3,500		3,500
15	51,997,236	403,304,309	0	455,301,545

Name of Respondent: Public Service Company of Oklahoma	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: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Respondent is an affiliated company of American Electric Power Service Corporation

2 Purchase Power Capacity Agreement Over/Under
3 Base Load Purchase Power Agreement Over/Under
4 Wind Energy
5 Dedicated Non-Firm Purchase
6 Capacity
7 Federal Energy Exchange Schedules for Customers on Respondent's System
8 Net Trading Purchases & Sales within ERCOT
9 Energy exchange to Grand River Dam Authority Customers on Respondent's System including Loss settlement
10 Atoka & Coalgate Waterworks on Respondent's System
11 Exchange Power with Oklahoma Municipal Power Authority Resources
12 Net Trading Purchases & Sales within Southwest Power Pool (SPP)
13 Excess power generated by PSO customers with solar panels

Name of Respondent: Public Service Company of Oklahoma	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 (l), 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)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)
1	[(a)] American Electric Power Service Corporation (1, 2, 3, 4)	various	various	OS	N/A	various	various			
2	American Electric Power Service Corporation (1, 2, 3)	various	various	OS	N/A	various	various			
3	Green Country Energy LLC (2)	Cogentrix	various	OS	N/A	Cogentrix	various			
4	Kiowa Power Partners, LLC (2)	Kiamichi Energy Facilities	various	OS	N/A	Kiamichi	various		174,534	174,534
5	Southwest Power Pool (3, 4, 5, 6, 7, 8)	various	various	OS	196	various	various			
6	Southwest Power Pool (3, 6, 7)	various	various	OS	196	various	various			
7	Western Farmers Electric Cooperative (2)	Western Farmers Electric Cooperative	Western Farmers Electric Cooperative	LFP	172	Lone Oak Substation	Bethel, Henryetta,West, Sardis, Nashob,Horntown, Allen,Hardy Sub, Webb City,Talihina, Shidler		332,088	332,088
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			4,633	4,633
2			(1,706,184)	(1,706,184)
3			56,225	56,225
4			47,236	47,236
5			8,628,424	8,628,424
6			49,243,763	49,243,763
7			22,611	22,611
35				

Name of Respondent: Public Service Company of Oklahoma	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: PaymentByCompanyOrPublicAuthority

Respondent is an affiliated company of American Electric Power Service Corporation

(2) Facilities charge

(3) Southwest Power Pool Base Plan Funding

(4) Network Integrated Transmission Service (NITS)

(5) Direct Assignment

(6) Point to point transmission and ancillary service

(7) FERC Formula Rate Settlement

(8) Prior Year

Name of Respondent: Public Service Company of Oklahoma	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					
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33					
34					
35					
36					
37					

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)
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				
Page 331					

Name of Respondent: Public Service Company of Oklahoma	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	American Electric Power Service Corporation (AEPSC) (1, 2, 3, 4, 5)	OS					95,304,500	95,304,500
2	Southwest Power Pool (3, 7)	OS					48,689,943	48,689,943
	TOTAL						143,994,443	143,994,443

Name of Respondent: Public Service Company of Oklahoma	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	384,503
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	70,204
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Associated Business Development	3,926,762
7	AEP Service Corporation and Other Affiliated	
8	Companies Billed to or from Respondent	201,914
9	Chamber of Commerce	80,308
10	Miscellaneous Minor Items Under $5,000	44,086
46	TOTAL	4,707,778

Name of Respondent: Public Service Company of Oklahoma	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			19,963,799		19,963,799
2	Steam Production Plant	44,990,059	764,077			45,754,136
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	34,970,102	853,486			35,823,588
7	Transmission Plant	31,701,204				31,701,204
8	Distribution Plant	95,307,417	15,294			95,322,711
9	Regional Transmission and Market Operation					
10	General Plant	12,131,779				12,131,779
11	Common Plant-Electric					
12	TOTAL	219,100,561	1,632,857	19,963,799		240,697,217

B. Basis for Amortization Charges

Section A Line 1 Column D represents amortization of capitalized software development costs over a 10 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	341 - Maverick	202	0 years		3.21%		
13	STEAM -- COAL/LIGNITE						
14	310 (Rights)	939	31 years	3%	3.86%		
15	341 - Southwest U4&5	4,849	48 years	4%	3.13%		
16	311 - Northeast U3	20,872	47 years	3%	2.89%		
17	341 - Weleetka	922	50 years	6%	5.12%		
18	312 - Northeast U3	378,098	47 years	3%	2.73%		
19	342 - Comanche	3	73 years	1%	2.2%		
20	314 - Northeast U3	46,246	47 years	3%	2.04%		
21	342 - Northeast U1&2	63	68 years	3%	1.53%		
22	315 - Northeast U3	21,256	47 years	3%	1.63%		
23	342 - Riverside Diesel	24	65 years	7%	3.16%		
24	316 - Northeast U3	18,736	47 years	3%	2.79%		
25	342 - Riverside U3&4	9,798	48 years	7%	2.21%		
26	342 - Southwest Diesel	59	75 years	4%	2.15%		
27	TOTAL COAL/LIGNITE	486,147					
28	342 - Tulsa Diesel	70	67 years	6%	1.14%		
29	342 - Weleetka Diesel	10	62 years	6%	1.72%		
30	STEAM -- GAS/OIL						
31	311.3 - Comanche	6,659	62 years	1%	3.39%		
32	342 - Weleetka	1,383	50 years	6%	2.05%		
33	311.3 - Northeast U1&2	13,826	66 years	3%	2.89%		
34	344 - Comanche	820	73 years	1%	1.21%		
35	311.3 - Riverside	13,958	67 years	7%	3.17%		
36	344 - Maverick	181,850	30 years		3.21%		
37	311.3 - Southwest	9,132	73 years	4%	5.24%		
38	344 - Northeast U1&2	761	68 years	3%	5.4%		
39	311.3 - Tulsa	8,879	71 years	6%	4.5%		
40	344 - Northeast U3	438	46 years	3%	0.62%		
41	312.3 - Comanche	68,818	62 years	1%	4.94%		
42	344 - 344 Riverside Diesel	470	65 years	7%	0.86%		
43	312.3 - Northeast U1&2	99,943	66 years	3%	2.73%		
44	344 - Riverside U3&4	47,613	48 years	7%	2.44%		
45	312.3 - Riverside	80,242	67 years	7%	2.06%		
46	344 -Rock Falls	246,537	25 years		2.42%		
47	312.3 - Southwest	39,496	73 years	4%	4.65%		
48	344 - Southwest Diesel	212	75 years	4%	0.73%		
49	312.3 - Tulsa	27,767	71 years	6%	3.75%		
50	344 - Southwest U4&5	47,936	48 years	4%	2.43%		
51	312.11 - Transp Eq	5,706	31 years	3%	0.05%		
52	344 - Sundance Wind	130,728	30 years		3.21%		
53	314.3 - Comanche	74,997	62 years	1%	3.71%		
54	344 - Traverse	572,091	30 years		3.21%		
55	314.3 - Northeast U1&2	153,756	66 years	3%	3.23%		
56	344 - Tulsa Diesel	608	67 years	6%	1.08%		
57	314.3 - Riverside	72,981	67 years	7%	2.39%		
58	344 - Weleetka Diesel	666	62 years	6%	1.41%		

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)
59	314.3 - Southwest	38,800	73 years	4%	4.83%		
60	344 - Weleetka	16,445	50 years	6%	2.53%		
61	314.3 - Tulsa	33,272	71 years	6%	3.08%		
62	345 - Northeast U1&2	84	68 years	3%	2.4%		
63	315.3 - Comanche	8,395	62 years	1%	3.2%		
64	345 - Riverside Diesel	69	65 years	7%	3.64%		
65	315.3 - Northeast U1&2	17,721	66 years	3%	3.24%		
66	345 - Riverside U3&4	3,850	48 years	7%	3%		
67	315.3 - Riverside	12,972	67 years	7%	1.46%		
68	345 - Southwest U4&5	9,572	48 years	4%	2.26%		
69	315.3 - Southwest	11,739	73 years	4%	5.05%		
70	345 - Weleetka Diesel	36	62 years	6%	1.11%		
71	315.3 - Tulsa	11,693	71 years	6%	5.54%		
72	345 - Weleetka	569	50 years	6%	12.48%		
73	316.3 - Comanche	3,787	62 years	1%	4.01%		
74	346 - Comanche	65	73 years	1%	5.94%		
75	316.3 - Northeast U1&2	9,041	66 years	3%	2.72%		
76	346 - Northeast U1&2 Diesel	3	68 years	3%	0.8%		
77	316.3 - Riverside	9,764	67 years	7%	4.34%		
78	316.3 - Southwest	2,624	73 years	4%	6.96%		
79	316.3 - Tulsa	4,670	71 years	6%	5.75%		
80	TOTAL GAS/OIL	840,638					
81	OTHER GENERATION						
82	346 - Riverside U3&4	185	48 years	7%	2.51%		
83	346 - Southwest U4&5	89	48 years	4%	3.25%		
84	346 - Weleetka Diesel	63	62 years	6%	22.57%		
85	346 - Weleetka	2,715	50 years	6%	3.85%		
86	346 - Maverick	52	0 years		3.21%		
87	346 - Traverse Wind	48	0 years		3.21%		

Name of Respondent: Public Service Company of Oklahoma	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			
						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)
1	Federal Energy Regulatory Commission Annual								
2	Assessment								
3	Oklahoma Commission Annual Assessment Fee	1,653,496		1,653,496		Electric	928	1,653,496	
4	Minor Expense < $25,000		245,342	245,342		Electric	928	245,342	
5	Expenses incurred in rate review before the Corporation Commission of the State of Oklahoma (OCC) - Cause No. PUD 201700151 Order No. 672864. Amortization period two years beginning March 2018.		611,807	611,807	396,115	Electric	928	(76,885)	852,251
6	Regulatory/Legislative Actions - Oklahoma		34,911	34,911		Electric	928	34,911	
7	Expenses incurred related to PSO's 2017 Base Rate Case					Electric	928		
8	Expenses incurred related to PSO's 2018 Base Rate Case		54,395	54,395		Electric	928	54,395	
9	Expenses incurred related to PSO's 2021 Base Rate Case		712,723	712,723		Electric	928	712,723	
10	Expenses incurred related to managing Formula Rates for AEP's West Operating Companies and Transco		61,344	61,344		Electric	928	61,344	
11	Labor Accrual		40	40		Electric	928	40	
12	2023 PSO Base Case		469,907	469,907		Electric	928	469,907	
13	PSO Distribution		1,018	1,018		Electric	928	1,018	
14	2022 PSO Renewable Filing		6,603	6,603		Electric	928	6,603	
15	All Companies		59	59		Electric	928	59	
16	2022 SWEPCO AR Turk Filing		17	17		Electric	928	17	
17	PSO 2021 Winter Strm Sectizatn		5,135	5,135		Electric	928	5,135	
18	PSO RFP Capacity Filing								
19	PSO Integrated Resource Plans								
20	Sundance Wind Facility		89,569	89,569		Electric	928	89,569	
21	Traverse Wind Facility BCO		184,092	184,092		Electric	928	184,092	
46	TOTAL	1,653,496	2,476,962	4,130,458	396,115			3,441,766	852,251

	AMORTIZED DURING YEAR		
Line No.	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1			
2			
3			
4			
5	928	688,692	559,674
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
46		688,692	559,674

Name of Respondent: Public Service Company of Oklahoma	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	A. (1) Generation						
2		IT - EPRI Annual Research Port		43,114	588, 566, 506	43,114	
3	A. (2) Transmission	2 Items < $50,000	4,058		566	4,058	
4	A. (3) Distribution	1 Item < $50,000	9,594		588	9,594	
5		EPRI Environmental Science		152,166	506	152,166	
6	A. (5) Environmental (other than equipment)	3 Items < $50,000	82		506	82	
7		23 Items < $50,000		114,584	506, 566, 588	114,584	
8	A. (6) Other	2 Items < $50,000	108		506, 566, 588	108	
9	B. (4) Research Support to Others	3 Items < $50,000		1,231	506	1,231	
10	(b) Fossil Fuel Steam	Generation Asset Management - Program Management	13,636		506	13,636	
11	A. (6)(a) Solar	Solar Field Panel Testing					
12	A. (6)(f) Metering	Advanced Metering Equipment (AMI) Test Bed Development	1,530		588	1,530	
13	B. (5) Total Cost Incurred Externally			843,686		843,686	
14	A. (6)(g) Research General	DTC Walnut Test Facility	299		566	299	
15		Total					
16			866		588	866	
17		1 Items < $50,000			566		
18	A. (7) Total Cost Incurred Internally		54,520			54,520	

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: Amount (f)	Unamortized Accumulation (g)
19	B. Electric R&D External	7 Items < $50,000		48,159	506, 566, ,588	48,159	
20		2 Items < $50,000	24,275		506	24,275	
21	B. Electrical R&D External	7 Items < $50,000		44,838	506,,566, 588	44,838	
22	B. (1) Electric Power Research Institute	EPRI Research Protfolio		568,822	506, 566, 588	568,822	
23		IT- EPRI Annual Research Port		43,587	506, 566, 588	43,587	
24	(c) Internal Combustion or Gas Turbines	None					
25	B. (1) Electric Power Research Institute	EPRI Research Portfolio		484,432	566, 506, 588	484,432	
26	(e) Unconventional Generation	Center for Energy Advancement Through Technology Innovation	71		506	71	
			Page 352-353				

Name of Respondent: Public Service Company of Oklahoma	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	18,920,018		
4	Transmission	1,931,329		
5	Regional Market			
6	Distribution	9,729,911		
7	Customer Accounts	2,248,669		
8	Customer Service and Informational	3,434,984		
9	Sales			
10	Administrative and General	938,430		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	37,203,341		
12	Maintenance			
13	Production	7,126,181		
14	Transmission	1,613,566		
15	Regional Market			
16	Distribution	14,852,824		
17	Administrative and General	1,580,407		
18	TOTAL Maintenance (Total of lines 13 thru 17)	25,172,978		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,046,199		
21	Transmission (Enter Total of lines 4 and 14)	3,544,895		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	24,582,735		
24	Customer Accounts (Transcribe from line 7)	2,248,669		
25	Customer Service and Informational (Transcribe from line 8)	3,434,984		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	2,518,837		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	62,376,319	3,995,289	66,371,608
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			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
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)	62,376,319	3,995,289	66,371,608
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	45,933,225	2,942,087	48,875,312
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	45,933,225	2,942,087	48,875,312
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,383,979	408,903	6,792,882
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	6,383,979	408,903	6,792,882
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	152 - Fuel Stock Undistributed	2,023,839		2,023,839
80	154 - Materials and Supplies			
81	163 - Stores Expense Undistributed	4,874,853	(4,874,853)	
82	183 - Prelim Survey	5,761	(5,761)	
83	184 - Clearing Accounts	2,465,665	(2,465,665)	
84	185 - ODD Temporary Facilities	211,676		211,676
85	186 - Misc Deferred Debits	708,901		708,901
86	188 - Research & Development			
87	401 - Operation Expense - Nonassociated			
88	402 - Maintenance Exp			
89	407 - Regulatory Debits			
90	417 - Misc Exp	3,378		3,378
91	418 - Nonoperating Rental Income			
92	421 - Misc Nonoperating Income			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
93	426 - Political Activities	28,797		28,797
94	451 - Misc Service Rev - Nonaffil			
95	456 - Other Electric Revenue			
95	TOTAL Other Accounts	10,322,870	(7,346,279)	2,976,591
96	TOTAL SALARIES AND WAGES	125,016,393		125,016,393
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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.

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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)	53,293,230	96,015,135	148,703,100	183,340,740
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(1,655,249)	(5,962,377)	(10,804,578)	(13,657,057)
4	Transmission Rights				
5	Ancillary Services	2,900,505	4,523,468	5,843,317	8,161,094
6	Other Items (list separately)				
7	Congestion	35,257,654	63,644,612	94,201,128	135,398,190
8	Operating Reserves	(939,637)	(2,509,611)	(4,126,004)	(5,477,422)
9	Transmission Congestion Revenue	(18,301,605)	(60,441,571)	(73,162,955)	(88,690,169)
10	Transmission Losses	3,343,886	7,389,389	16,256,084	21,686,975
46	TOTAL	73,898,784	102,659,045	176,910,092	240,762,351

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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)						

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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	0								
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	[a]0

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FOOTNOTE DATA

(a) Concept: OtherService

Public Service Company of Oklahoma's transmission service is administered through a Regional Transmission Organization (RTO) and requested information is not available on an individual company basis.

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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: Public Service Company of Oklahoma	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)	18,515,197
3	Steam	6,936,075	23	Requirements Sales for Resale (See instruction 4, page 311.)	8,119
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	458,134
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	13
7	Other	2,522,355	27	Total Energy Losses	1,160,400
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	9,458,430	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	20,141,863
10	Purchases (other than for Energy Storage)	10,683,433			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	747,116			
13	Delivered	747,116			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	506,622			
17	Delivered	506,622			
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)	20,141,863			

Name of Respondent: Public Service Company of Oklahoma	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	1,607,001	23,902	2,986	30	12
30	February	1,470,116	36,017	2,792	1	9
31	March	1,503,985	43,719	2,426	20	9
32	April	1,403,503	50,629	2,450	14	17
33	May	1,600,911	23,982	3,244	31	17
34	June	1,820,876	37,205	4,119	29	16
35	July	2,240,966	168,298	4,038	31	16
36	August	2,241,095	34,657	4,287	21	18
37	September	1,657,265	(65,481)	4,027	5	17
38	October	1,494,871	72,605	3,116	2	17
39	November	1,483,704	21,908	2,600	8	15
40	December	1,617,569	19,160	2,484	11	8
41	Total	20,141,862	466,601			

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: COMANCHE	Plant Name: NORTHEASTERN 1&2	Plant Name: NORTHEASTERN 3	Plant Name: North Central Wind	Plant Name: RIVERSIDE 1 & 2	Plant Name: Riverside 3 & 4	Plant Name: Rock Falls	Plant Name: SOUTHWESTERN 1 - 3
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Combined Cycle	Steam	Steam	Wind	Steam	Gas Turbine	Wind	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conv. Outdoor Boiler	Conv. Outdoor Boiler	Conv. Outdoor Boiler	Wind Generator	Conv. Outdoor Boiler	No Boiler	Wind Generator	Conv. Outdoor Boiler
3	Year Originally Constructed	1973	1961	1979	2021	1974	2008	2023	1952
4	Year Last Unit was Installed	1974	2001	1980	2022	1976	2008	2023	1967
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	225.00	856.00	469.00	668.09	907.00	152.00	155	458.00
6	Net Peak Demand on Plant - MW (60 minutes)	248	854	472	602	870	156	282	447
7	Plant Hours Connected to Load	3,333	5,207	5,605	8,250	629	3,086	5,945	6,683
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0	0	0	0
9	When Not Limited by Condenser Water	0	0	0	0	0	0	0	0
10	When Limited by Condenser Water	266	918	941	0	908	151	0	466
11	Average Number of Employees	19	35	79	31	31	0	7	31
12	Net Generation, Exclusive of Plant Use - kWh	512,209,000	2,287,619,000	1,677,210,000	2,209,800,952	1,102,234,000	91,211,000	312,554,323	848,041,000
13	Cost of Plant: Land and Land Rights	345,962	101,506	3,960,322	297,665	1,376,358		87,000	191,512
14	Structures and Improvements	6,740,213	13,860,429	20,872,167	266,348	14,018,716		47,479	9,465,454
15	Equipment Costs	156,731,078	281,593,354	492,395,420	885,318,537	177,165,958	61,446,016	247,296,668	94,608,341
16	Asset Retirement Costs	842,350	2,488,464	11,906,728	20,491,208	3,218,362		5,835,982	942,562
17	Total cost (total 13 thru 20)	164,659,603	298,043,753	529,134,637	906,373,758	195,779,394	61,446,016	253,267,129	105,207,869
18	Cost per KW of Installed Capacity (line 17/5) Including	731.8205	348.1820	1,128.2188	1,356.6642	215.8538	404.2501	1,633.9815	229.7115
19	Production Expenses: Oper, Supv, & Engr	1,173,154	4,255,928	3,434,127	816,167	2,429,602	114,991	1,262,177	1,727,396
20	Fuel	14,362,611	60,760,009	292,050	0	32,438,630	5,508,604		30,788,483
21	Coolants and Water (Nuclear Plants Only)	0			0				
22	Steam Expenses	1,382,293	1,372,812	2,356,254	3,776	251,422			2,090,636
23	Steam From Other Sources				0				
24	Steam Transferred (Cr)				0				
25	Electric Expenses	60,607	863,182	1,158,989	766,225	2,146,065	(1,382)	427,160	590,002
26	Misc Steam (or Nuclear) Power Expenses	884,612	1,128,393	2,399,514	77,493	950,965			870,589
27	Rents	3,253	14,527	10,651		6,999			5,385
28	Allowances	(3)	(13)	(10)	0	(6)			(5)
29	Maintenance Supervision and Engineering	311,073	759,741	872,981	1,565	185,039			363,550
30	Maintenance of Structures	506,167	457,395	609,726	0	719,102	529	7,860	24,745
31	Maintenance of Boiler (or reactor) Plant	563,722	3,128,758	6,465,730	0	1,709,709			1,568,445
32	Maintenance of Electric Plant	1,743,878	2,663,052	1,274,958	3,075,081	1,664,791	292,559	458,927	647,796
33	Maintenance of Misc Steam (or Nuclear) Plant	646,462	487,634	388,439	0	316,659	(9)		129,854
34	Total Production Expenses	21,637,829	75,891,418	19,263,409	4,740,308	42,818,977	5,915,292	2,156,124	38,806,876

Line No.	Item (a)	Plant Name: COMANCHE	Plant Name: NORTHEASTERN 1&2	Plant Name: NORTHEASTERN 3	Plant Name: North Central Wind	Plant Name: RIVERSIDE 1 & 2	Plant Name: Riverside 3 & 4	Plant Name: Rock Falls	Plant Name: SOUTHWESTERN 1 - 3
35	Expenses per Net kWh	0.0422	0.0332	0.0115	0.0021	0.0388	0.0649	0.0069	0.0458

Line No.	Item (a)	Plant Name: [a] Southwestern 4 & 5	Plant Name: TULSA	Plant Name: WELEETKA
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	No Boiler	Conv. Outdoor Boiler	Conventional
3	Year Originally Constructed	2008	1923	1975
4	Year Last Unit was Installed	2008	1958	1976
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	151.00	308.00	150.00
6	Net Peak Demand on Plant - MW (60 minutes)	171	319	84
7	Plant Hours Connected to Load	1,283	3,624	76
8	Net Continuous Plant Capability (Megawatts)	0	0	0
9	When Not Limited by Condenser Water	0	0	0
10	When Limited by Condenser Water	170	315	200
11	Average Number of Employees	0	24	2
12	Net Generation, Exclusive of Plant Use - kWh	196,096,000	214,317,000	7,138,000
13	Cost of Plant: Land and Land Rights	0	97,253	62,660
14	Structures and Improvements	4,849,168	8,878,502	922,151
15	Equipment Costs	57,596,190	77,843,885	21,121,285
16	Asset Retirement Costs	0	5,112,188	16,036
17	Total cost (total 13 thru 20)	62,445,358	91,931,828	22,122,132
18	Cost per KW of Installed Capacity (line 17/5) Including	413.5454	298.4800	147.4809
19	Production Expenses: Oper, Supv, & Engr	281,768	687,393	73,534
20	Fuel	7,868,182	8,635,732	310,787
21	Coolants and Water (Nuclear Plants Only)	0		
22	Steam Expenses	299,874	1,515,441	
23	Steam From Other Sources	0		
24	Steam Transferred (Cr)	0		
25	Electric Expenses	(2,971)	651,625	376,600
26	Misc Steam (or Nuclear) Power Expenses	11,270	1,231,684	12
27	Rents	0	1,361	
28	Allowances	0	(1)	
29	Maintenance Supervision and Engineering	0	224,389	2,229
30	Maintenance of Structures	0	765,630	20,864
31	Maintenance of Boiler (or reactor) Plant	0	1,806,285	
32	Maintenance of Electric Plant	278,407	2,398,632	155,445
33	Maintenance of Misc Steam (or Nuclear) Plant	41,391	379,285	(1)
34	Total Production Expenses	8,777,921	18,297,456	939,470
35	Expenses per Net kWh	0.0448	0.0854	0.1316

35	**Plant Name**	COMANCHE	COMANCHE	NORTHEASTERN 1&2	NORTHEASTERN 1&2	NORTHEASTERN 3	NORTHEASTERN 3	NORTHEASTERN 3	North Central Wind
36	Fuel Kind	Diesel	GAS	Diesel	GAS	COAL	Diesel/Compo	GAS	Wind
37	Fuel Unit	bbl	Mcf	bbl	Mcf	t	bbl	Mcf	
38	Quantity (Units) of Fuel Burned	4	4,805,875		20,715,082	1,010,626	5	114,562	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	140,000	1,020		1,020	8,635	140,000	1,020	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5,102.220	2.860	0.000	2.810	36.034	1,017.930	2.420	
41	Average Cost of Fuel per Unit Burned	5,102.220	2.860	0.000	2.810	36.370	1,017.930	2.420	
42	Average Cost of Fuel Burned per Million BTU	867.730	2.810	0.000	2.750	2.110	173.120	2.380	
43	Average Cost of Fuel Burned per kWh Net Gen		0.030	0.000	0.030	0.020		0.020	
44	Average BTU per kWh Net Generation		9,570.000	0.000	9,236.000	10,476.000		10,476.000	

35	**Plant Name**	RIVERSIDE 1 & 2	RIVERSIDE 1 & 2	RIVERSIDE 1 & 2	Riverside 3 & 4	Rock Falls	SOUTHWESTERN 1 - 3	Southwestern 4 & 5	TULSA	TULSA	WELEETKA	WELEETKA
36	Fuel Kind	Composite	GAS	Oil/Diesel	GAS	Wind	GAS	GAS	DIESEL	GAS	Diesel	GAS
37	Fuel Unit		Mcf	bbl	Mcf		Mcf	Mcf	bbl	Mcf	bbl	Mcf
38	Quantity (Units) of Fuel Burned		12,137,082	9	1,275,326		10,147,069	2,557,183	78	2,834,264	7	110,676
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		1,032	140,000	906		1,044	924	140,000	1,020	140,000	1,020
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		2.550	500.330	4.210		2.910	2.960	875.670	2.920	1,408.970	2.680
41	Average Cost of Fuel per Unit Burned		2.550	500.330	4.210		2.910	2.960	0.000	2.920	1,408.970	2.680
42	Average Cost of Fuel Burned per Million BTU		2.470	85.090	4.640		2.780	3.210	0.000	2.860	239.620	2.630
43	Average Cost of Fuel Burned per kWh Net Gen		0.030	0.000	0.060		0.030	0.040	0.000	0.040		0.040
44	Average BTU per kWh Net Generation	11,563.000	11,364.000	0.000	12,665.000		12,495.000	12,045.000	0.000	13,489.000		15,815.000

Name of Respondent: Public Service Company of Oklahoma	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: PlantName

In April 2021, PSO acquired a 44.5% ownership share of Sundance wind facility (199 MW total nameplate capacity) which was placed in-service in April 2021.

In September 2021, PSO acquired a 44.5% ownership share of Maverick wind facility (287 MW total nameplate capacity) which was placed in-service in September 2021.

Name of Respondent: Public Service Company of Oklahoma	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)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

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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)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
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	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
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	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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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Name of Respondent: Public Service Company of Oklahoma	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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	Internal Combustion:												
2	Tulsa Diesel	1967	8.25			678,776	82,276		68,677		Oil	14,892.00	
3	Riverside Diesel	1976	2.75			563,209	204,803		4,670		Oil	8,509.00	
4	Northeastern 1&2 Diesel	1968	2.75			508,092	142,228		9,138		Oil		
5	Northeastern 3&4 Diesel	1980	1.20			437,950	364,958		4,806		Oil	17,312.00	
6	Weleetka Diesel	1963	4.00			776,384	194,096		9,326		Oil	23,962.00	
7	Comanche Diesel	1962	4.00			775,321	193,830		20,044		Oil	86,773.00	
8	Southwestern Diesel	1962	2.00			271,295	135,648				Oil		
9	Note: Operation and Maintenance expenses												
10	are immaterial in nature and are no longer												
11	available for specific diesel unit.												

Name of Respondent: Public Service Company of Oklahoma	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												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
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25												
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30												
31												
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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4							
5							
6							
7							
8							
9							
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35	0	0	0		0	0	0

Name of Respondent: Public Service Company of Oklahoma	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									
8									
9									
10									
11									
12									
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29									
30									
31									
32									
33									
34									
35									
36	TOTAL								

Name of Respondent: Public Service Company of Oklahoma	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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	TL90-901 ONETA SUB	OG&E INTERCONNECT CLARKSVILLE	345.00	345.00	3	16.21	0.00	1	2267.0 ACAR
2	TL90-902 ONETA SUB	RIVERSIDE PLANT	345.00	345.00	3	1.23	0.00	1	2156.0 ACSR
3	TL90-902 ONETA SUB	RIVERSIDE PLANT	345.00	345.00	3	13.32	0.00	1	2168.0 ACAR
4	TL90-902 ONETA SUB	RIVERSIDE PLANT	345.00	345.00	3	2.23	0.00	1	2267.0 ACAR
5	TL90-902 ONETA SUB	RIVERSIDE PLANT	345.00	345.00	3	1.45	0.00	2	2267.0 ACAR
6	TL90-903 NORTHEASTERN POWER STATION	ONETA	345.00	345.00	2	30.78	0.00	1	2267.0 ACAR
7	TL90-903 NORTHEASTERN POWER STATION	ONETA	345.00	345.00	3	1.69	0.00	1	2267.0 ACAR
8	TL90-904 VALLIANT	PITTSBURG	345.00	345.00	2	70.20	0.00	1	2x795.0 ACSR
9	TL90-905 VALLIANT SUB	SWEPCO INTERCONNECT OKLAHOMA-TEXAS STATE LINE	345.00	345.00	1	0.22	0.00	1	2x795.0 ACSR
10	TL90-905 VALLIANT SUB	SWEPCO INTERCONNECT OKLAHOMA-TEXAS STATE LINE	345.00	345.00	2	20.40	0.00	1	2x795.0 ACSR
11	TL90-906 RIVERSIDE PLANT	WEKIWA SUB	345.00	345.00	1	0.76	0.00	1	2156.0 ACSR
12	TL90-906 RIVERSIDE PLANT	WEKIWA SUB	345.00	345.00	3	0.80	0.00	2	2267.0 ACAR AND 1272 ACSR
13	TL90-906 RIVERSIDE PLANT	WEKIWA SUB	345.00	345.00	2	18.80	0.00	1	2267.0 ACAR
14	TL90-906 RIVERSIDE PLANT	WEKIWA SUB	345.00	345.00	3	1.30	0.00	1	2267.0 ACAR
15	TL90-907 RIVERSIDE PLANT	OG&E INTERCONNECT KENDRICK	345.00	345.00	3	47.20	0.00	1	2267.0 ACAR
16	TL90-907 RIVERSIDE PLANT	OG&E INTERCONNECT KENDRICK	345.00	345.00	3	3.80	0.00	2	2267.0 ACAR and 2x 795 ACSR
17	TL90-907 RIVERSIDE PLANT	OG&E INTERCONNECT KENDRICK	345.00	345.00	2	1.80	0.00	1	2267 ACAR
18	TL90-908 DELAWARE PLANT	KG&E INTERCONNECT KANSAS STATE LINE	345.00	345.00	2	28.22	0.00	1	2x795.0 ACSR
19	TL90-908 DELAWARE PLANT	KG&E INTERCONNECT KANSAS STATE LINE	345.00	345.00	3	1.65	0.00	2	2x795 ACSR
20	TL90-909 NORTHEASTERN POWER STATION	TULSA NORTH	345.00	345.00	3	19.35	0.00	2	2267.0 ACAR and 795 ACSR
21	TL90-909 NORTHEASTERN POWER STATION	TULSA NORTH	345.00	345.00	3	1.40	0.00	1	2267 ACAR
22	TL90-909 NORTHEASTERN POWER STATION	TULSA NORTH	345.00	345.00	2	1.95	0.00	2	2267.0 ACAR and 795 ACSR
23	TL90-914 TULSA NORTH SUB	WEKIWA SUB	345.00	345.00	2	17.50	0.00	1	2267.0 ACAR
24	TL90-915 PITTSBURG SUB	OG&E INTERCONNECT ARDMORE	345.00	345.00	2	85.60	0.00	1	2x954.0 ACSR
25	TL90-915 PITTSBURG SUB	OG&E INTERCONNECT ARDMORE	345.00	345.00	3	1.80	0.00	2	2x 795 ACSR
26	TL90-916 LAWTON EASTSIDE SUB	OG&E INTERCONNECT ARDMORE	345.00	345.00	2	0.00	1.77	1	2x954 ACSR
27	TL90-916 LAWTON EASTSIDE SUB	OG&E INTERCONNECT ARDMORE	345.00	345.00	2	69.32	0.00	1	2x954.0 ACSR

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)	Size of Conductor and Material (i)
28	TL90-916 LAWTON EASTSIDE SUB	OG&E INTERCONNECT ARDMORE	345.00	345.00	3	0.41	0.00	2	2x954.0 ACSR
29	TL90-917 PITTSBURG SUB	OG&E INTERCONNECT ASHLAND	345.00	345.00	2	10.96	0.00	1	2x795.0 ACSR
30	TL90-918 LAWTON EASTSIDE SUB	OKLAUNION SUB	345.00	345.00	2	66.60	0.00	1	2x795.0 ACSR
31	TL90-919 LAWTON EASTSIDE SUB	OG&E INTERCONNECT APACHE	345.00	345.00	2	21.30	0.00	1	2x795.0 ACSR
32	TL90-919 LAWTON EASTSIDE SUB	OG&E INTERCONNECT APACHE	345.00	345.00	1	0.15	0.00	1	2x795.0 ACSR
33	TL90-921 CLARKSVILLE	OG&E INTERCONNECT	345.00	345.00	3	0.85	0.00	1	2156.0 ACSR
34	TL90-921 CLARKSVILLE	OG&E INTERCONNECT	345.00	345.00	3	1.43	0.00	1	2168.0 ACAR
35	TL90-922 DELAWARE SUB	KG&E INTERCONNECT	345.00	345.00	2	24.48	0.00	1	2x795.0 ACSR
36	TL90-923 RIVERSIDE SWITCHYARD	Co-GENTRIX SWITCHYARD	345.00	345.00	1	1.00	0.00	1	2-1272.0 ACSR
37	TL90-924 ONETA	ONETA ENERGY CENTER (CAL	345.00	345.00	2	0.14	0.00	1	2 -1272.0 ACSR
38	TL90-925 ONETA	ONETA ENERGY CENTER (CAL	345.00	345.00	2	0.15	0.00	1	2 -1272.0 ACSR
39	SubTotal 345 kV Lines in OK		0.00	0.00		586.40	2.18	22	
40	TL81-609 OKLAUNION DC TIE	DC TERMINAL NORTH	345.00	345.00	1	0.01	0.00	1	1926.9 ACSR
41	TL90-920 OKLAUNION SUB	SPS INTERCONNECT	345.00	345.00	2	0.88	0.00	1	2x795.0 ACSR
42	SubTotal 345 kV Lines in TX		0.00	0.00		0.89	0.00	3	
43	TL90-910 CATOOSA SUB	GRADA INTERCONNECT	345.00	345.00	3	13.07	0.00	1	2267.0 ACAR
44	TL90-910 CATOOSA SUB	GRADA INTERCONNECT	345.00	345.00	2	1.15	0.00	2	2267 ACAR and 795 ACSR
45	TL90-910 CATOOSA SUB	GRADA INTERCONNECT	345.00	345.00	2	0.30	0.00	1	2267 ACAR
46	SubTotal 345 kV Lines (Chan		0.00	0.00		14.52	0.00	1	
47	Total 345 kV Lines (All)		0.00	0.00		601.81	2.18	26	
48	TL85-100 ELK CITY SUB	SPS INTERCONNECT TEXAS STATE	230.00	230.00	2	34.12	0.00	1	795.0 ACSR
49	Total 230 kV Lines (All)		0.00	0.00		34.12	0.00	1	
50	TL83-555 GROVE	EMPIRE ELECTRIC	161.00	161.00	2	7.61	0.80	1	(T2) 397 ACSR
51	Total 161 kV Lines (All)		0.00	0.00		7.61	0.80	1	
52	TL81-501 (RADIAL) SOUTHEAST SUB	KENOSHA SUB	138.00	138.00	1	4.40	0.00	1	477.0 ACSR
53	TL81-502 FORD GLASS PLANT SUB	SOUTHEAST SUB	138.00	138.00	1	2.38	0.00	2	795 AND 1272 ACSR
54	TL81-502 FORD GLASS PLANT SUB	SOUTHEAST SUB	138.00	138.00	2	0.74	0.00	1	795 ACSR
55	TL81-502 FORD GLASS PLANT SUB	SOUTHEAST SUB	138.00	138.00	1	1.83	0.00	1	795.0 ACSR
56	TL81-502A (RADIAL) 53RD & GARNETT TAP		138.00	138.00	1	0.75	0.00	2	T2 4/0 and 477 ACSR
57	TL81-506 CLINTON JCT	WEATHERFORD WINDFARM	138.00	138.00	1	0.56	0.00	1	(T2) 636 ACSR
58	TL81-506A (RADIAL)	WEATHERFORD CITY	138.00	138.00	1	3.35	0.00	1	(T2) 636 ACSR

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
59	TL81-506B CLINTON NATURAL GAS TAP	TLN114:0506A	138.00	138.00	1	3.01	0.00	1	(T2) 636 ACSR
60	TL81-506B CLINTON NATURAL GAS TAP	TLN114:0506B	138.00	138.00	1	0.59	0.00	1	T2 636 ACSR
61	TL81-507 (RADIAL) VALLIANT SUB	WEYCO VALLIANT SUB	138.00	138.00	1	2.72	0.00	1	477.0 ACSR
62	TL81-507 (RADIAL) VALLIANT SUB	WEYCO VALLIANT SUB	138.00	138.00	2	1.65	0.00	1	795.0 ACSR
63	TL81-509 CORNVILLE SUB	NORGE ROAD SUB	138.00	138.00	2	0.27	0.00	1	397.0 ACSR
64	TL81-509 CORNVILLE SUB	NORGE ROAD SUB	138.00	138.00	1	0.07	0.00	1	1272 ACSR
65	TL81-509 CORNVILLE SUB	NORGE ROAD SUB	138.00	138.00	2	4.55		2	397.5 ACSR
66	TL81-510A (RADIAL) CLINTON SHERMAN AFB TAP		138.00	138.00	1	4.48	0.00	1	1272 ACSR
67	TL81-512 ONETA SUB	BROKEN ARROW 81ST STREET SUB	138.00	138.00	1	2.08	0.00	1	1590 ACSR
68	TL81-512 ONETA SUB	BROKEN ARROW 81ST STREET SUB	138.00	138.00	1	0.21	0.00	2	1272.0 ACSR AND T2 795 ACSR
69	TL81-512 ONETA SUB	BROKEN ARROW 81ST STREET SUB	138.00	138.00	1	5.85	0.00	2	1590.0 ACSR AND 1272 ACSR
70	TL81-512 ONETA SUB	BROKEN ARROW 81ST STREET SUB	138.00	138.00	1	0.10	0.00	1	477.0 ACSR
71	TL81-513 RIVERSIDE PLANT SUB	EAST 61ST ST	138.00	138.00	1	0.44	0.00	1	2X 795 ACSR
72	TL81-513 RIVERSIDE PLANT SUB	EAST 61ST ST	138.00	138.00	2	1.00	0.00	1	2X 795 ACSR
73	TL81-513 RIVERSIDE PLANT SUB	EAST 61ST ST	138.00	138.00	3	0.55	0.00	1	2X 795 ACSR
74	TL81-513 RIVERSIDE PLANT SUB	EAST 61ST ST	138.00	138.00	1	0.41	1.87	1	1272.0 ACSR
75	TL81-513A (RADIAL) WARREN MEDICAL CENTER TAP		138.00	138.00	2	1.39	0.00	1	266.8 ACSR
76	TL81-513A (RADIAL) WARREN MEDICAL CENTER TAP		138.00	138.00	1	1.63	0.00	1	477.0 ACSR
77	TL81-513B (RADIAL) ORAL ROBERTS TAP		138.00	138.00	1	1.19	0.00	1	477 ASCR
78	TL81-514 BIXBY 111TH ST SUB	ONETA SUB	138.00	138.00	1	5.72		1	1272.0 ACSR
79	TL81-514 BIXBY 111TH ST SUB	ONETA SUB	138.00	138.00	1	0.20	0.00	2	1272 ACSR AND 1590 ASCR
80	TL81-515 COMANCHE PLANT	LAWTON EASTSIDE SUB	138.00	138.00	3	5.08	0.00	3	795.0 ACSR, 795 ACSR, AND 266.8
81	TL81-515 COMANCHE PLANT	LAWTON EASTSIDE SUB	138.00	138.00	3	0.17	0.00	2	795 ACSR AND 266.8 ACSR
82	TL81-515 COMANCHE PLANT	LAWTON EASTSIDE SUB	69.00	138.00	1	0.35	0.00	1	795 ACSR
83	TL81-516 VALLIANT SUB	CRAIG JCT SUB	138.00	138.00	2	0.50	0.00	2	795 ACSR AND 795 ACSR
84	TL81-516 VALLIANT SUB	CRAIG JCT SUB	138.00	138.00	2	11.90	0.00	1	795.0 ACSR/SD 42/7 (MACAW)
85	TL81-516 VALLIANT SUB	CRAIG JCT SUB	138.00	138.00	2	5.85	0.00	1	795.0 ACSR
86	TL81-517 SWPA W/TAP	EXPLORER PUMP SUB	138.00	138.00	1	0.42	0.00	1	477 ACSR

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
87	TL81-517 SWPA W/TAP	EXPLORER PUMP SUB	138.00	138.00	1	0.03	0.00	1	397.5 ACSR
88	TL81-518 (RADIAL) TULSA NORTH	WEST EDISON SUB	138.00	138.00	1	8.20	0.00	1	477.0 ACSR
89	TL81-518 (RADIAL) TULSA NORTH	WEST EDISON SUB	138.00	138.00	2	1.12	0.00	1	477 ACSR
90	TL81-518 (RADIAL) TULSA NORTH	WEST EDISON SUB	138.00	138.00	1	0.76	0.00	2	477 26/7 ACSR and 477 18/1 ACSR
91	TL81-518 (RADIAL) TULSA NORTH	WEST EDISON SUB	138.00	138.00	1	2.10	0.00	1	795 ACSR
92	TL81-519 TULSA PLANT	36TH & LEWIS SUB	138.00	138.00	1	1.41	0.00	1	2156.0 ACSR
93	TL81-519 TULSA PLANT	36TH & LEWIS SUB	138.00	138.00	3	0.47	0.00	1	2x795.0 ACSR
94	TL81-519 TULSA PLANT	36TH & LEWIS SUB	138.00	138.00	3	0.11	0.00	1	2156 ACSR
95	TL81-519 TULSA PLANT	36TH & LEWIS SUB	138.00	138.00	3	0.02	0.00	2	2156 ACSR AND 2156 ACSR
96	TL81-520 TULSA SOUTHEAST SUB	36TH & LEWIS SUB	138.00	138.00	1	3.10	0.00	1	1272.0 ACSR
97	TL81-520A (RADIAL) ZUNIS TAP		138.00	138.00	1	3.60	0.00	1	477.0 ACSR
98	TL81-520B (RADIAL) 52ND & DELAWARE EAST TAP		138.00	138.00	1	1.96	0.00	1	477.0 ACSR
99	TL81-520B (RADIAL) 52ND & DELAWARE EAST TAP		138.00	138.00	1	0.10	0.00	2	477.0 ACSR and 477 ACSR
100	TL81-521 RIVERSIDE PLANT	TULSA PLANT	138.00	138.00	1	3.27	0.00	1	795 ASCR
101	TL81-521 RIVERSIDE PLANT	TULSA PLANT	138.00	138.00	2	3.37	0.00	1	795 ACSR
102	TL81-521 RIVERSIDE PLANT	TULSA PLANT	138.00	138.00	3	0.07	0.00	2	795 ACSR
103	TL81-521 B (RADIAL) JENKS TAP		138.00	138.00	2	1.59	0.00	0	477.0 ACSR
104	TL81-521 C (RADIAL) SOUTHERN HILLS TAP		138.00	138.00	3	0.65	0.00	0	559.6 AAAC
105	TL81-521A (RADIAL) 52ND & DELAWARE WEST TAP		138.00	138.00	1	3.20	0.00	2	795.0 ACSR and 1272 ACSR
106	TL81-522 RIVERSIDE PLANT	TULSA PLANT W/TAP	138.00	138.00	3	0.31	0.00	2	556.5 ACSR and 795 ACSR
107	TL81-522 RIVERSIDE PLANT	TULSA PLANT W/TAP	138.00	138.00	2	5.39	0.00	1	556.5 ACSR
108	TL81-522 RIVERSIDE PLANT	TULSA PLANT W/TAP	138.00	138.00	1	0.10	0.00	1	795 ACSR
109	TL81-522 RIVERSIDE PLANT	TULSA PLANT W/TAP	138.00	138.00	1	0.07	0.00	3	795 ACSR, 795 ACSR and 1272 ACSR
110	TL81-522 RIVERSIDE PLANT	TULSA PLANT W/TAP	138.00	138.00	1	0.05	0.00	2	2x 795 ACSR and 1272 ACSR
111	TL81-523 RIVERSIDE PLANT	OG&E INTERCONNECT	138.00	138.00	2	1.90	1.90	3	1020 ACSR, 795 ACSR AND 1272 KCM
112	TL81-524 (RADIAL) SAND SPRINGS SUB	DENVER SUB	138.00	138.00	1	0.26	0.00	2	1272 ACSR
113	TL81-524 (RADIAL) SAND SPRINGS SUB	DENVER SUB	138.00	138.00	1	0.30	0.00	2	556.5 ACSR and 636 ACSR
114	TL81-524 (RADIAL) SAND SPRINGS SUB	DENVER SUB	138.00	138.00	1	0.22	0.00	1	636 ACSR

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
115	TL81-524 (RADIAL) SAND SPRINGS SUB	DENVER SUB	138.00	138.00	1	4.07	0.00	1	397 ACSR
116	TL81-524 (RADIAL) SAND SPRINGS SUB	DENVER SUB	138.00	138.00	1	0.18	0.00	1	795 ACSR
117	TL81-524 (RADIAL) SAND SPRINGS SUB	DENVER SUB	138.00	138.00	1	2.40	0.00	1	556.5 ACSR
118	TL81-525 TULSA PLANT	DENVER	138.00	138.00	1	0.06	0.00	1	477.0 ACSR
119	TL81-525 TULSA PLANT	DENVER	138.00	138.00	1	5.87	0.00	1	795.0 AAC
120	TL81-526 CATOOSA	MAID SUB w/TAP	138.00	138.00	3	0.20	0.00	1	795 ACSR
121	TL81-526 CATOOSA	MAID SUB w/TAP	138.00	138.00	2	11.22	0.00	1	1272 ACSR
122	TL81-526 CATOOSA	MAID SUB w/TAP	138.00	138.00	1	4.88	0.00	1	1272 ACSR
123	TL81-526 CATOOSA	MAID SUB w/TAP	138.00	138.00	1	3.75	0.00	1	1272 ACSR
124	TL81-526 CATOOSA	MAID SUB w/TAP	138.00	138.00	2	3.63	0.00	2	1272 ACSR and 2/0 ACSR
125	TL81-526 CATOOSA	MAID SUB w/TAP	138.00	138.00	1	0.70	0.00	2	1272 ACSR and 1272 ACSR
126	TL81526A : (RADIAL) INOLA TAP		138.00	138.00	1	2.00	0.00	1	795 ACSR
127	TL81526B : (RADIAL) CHOUTEAU 138kV TAP		138.00	138.00	1	5.63	0.00	1	T2 4/0 6/1 PENGUIN
128	TL81-527 LAWTON EASTSIDE	112TH & W. GORE	138.00	138.00	1	15.64	0.00	1	795.0 ACSR
129	TL81-527A (RADIAL) LAWTON WESTSIDE SOUTH TAP		138.00	138.00	1	0.45	0.00	1	795.0 ACSR
130	TL81-528 WEKIWA SUB	TULSA NORTH SUB	138.00	138.00	2	9.00	0.00	2	1272 ACSR and 1272 ACSR/AW
131	TL81-528 WEKIWA SUB	TULSA NORTH SUB	138.00	138.00	3	10.84	0.00	1	636 ACSR
132	TL81-528 WEKIWA SUB	TULSA NORTH SUB	138.00	138.00	3	0.10	0.00	2	1272 ACSR and 477 HAWK
133	TL81-528 WEKIWA SUB	TULSA NORTH SUB	138.00	138.00	3	0.22	0.00	1	795.0 ACSR
134	TL81-528A (RADIAL) PINE & PEORIA TAP		138.00	138.00	1	3.18	0.00	1	266.8 ACSR
135	TL81-528A (RADIAL) PINE & PEORIA TAP		138.00	138.00	1	1.17	0.00	1	477 ACSR
136	TL81-528A (RADIAL) PINE & PEORIA TAP		138.00	138.00	1	1.47	0.00	1	795 ACSR
137	TL81-529 WEKIWA SUB	KEYSTONE (SWPA) SUB	138.00	138.00	1	0.20	0.00	1	2 - 1272 ACSR
138	TL81-530 RIVERSIDE 345kV SUB	RIVERSIDE 138kV LINE SUB	138.00	138.00	1	1.13	0.00	1	2 -2156.0 ACSR
139	TL81-530 RIVERSIDE 345kV SUB	RIVERSIDE 138kV LINE SUB	138.00	138.00	1	0.38	0.00	2	2- 2156 ACSR
140	TL81-531 (RADIAL) HOLLIS TAP	HOLLIS 138kV LINE (INTERCONNECT-TX PORTION)	138.00	138.00	1	16.00	0.00	1	477.0 ACSR
141	TL81-531 (RADIAL) HOLLIS TAP	HOLLIS 138kV LINE (INTERCONNECT-TX PORTION)	138.00	138.00	2	1.00	0.00	1	477.0 ACSR
142	TL81-534 WEKIWA SUB	ARMCO SUB	138.00	138.00	1	5.69	0.00	1	1272.0 ACSR
143	TL81-534 WEKIWA SUB	ARMCO SUB	138.00	138.00	3	0.12	0.57	2	1272 ACSR AND 2267 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
144	TL81-534 WEKIWA SUB	ARMCO SUB	138.00	138.00	2	0.07	0.00	1	795 ACSR
145	TL81-534 WEKIWA SUB	ARMCO SUB	138.00	138.00	2	0.11	0.00	1	1272 ACSR
146	TL81-536 SHIDLER SUB	OG&E INTERCONNECT (OSAGE)	138.00	138.00	2	5.34	0.00	1	477.0 ACSR
147	TL81-537 ELK CITY SUB	ELK CITY FALCON ROAD SUB	138.00	138.00	1	4.40	0.00	1	477.0 ACSR
148	TL81-537 ELK CITY SUB	ELK CITY FALCON ROAD SUB	138.00	138.00	1	14.60		1	(T2) 423.0 KCM (2-4/0 KC ACSR) 6/1 PENGUIN
149	TL81-539 MCALESTER SOUTH SUB	LONE OAK SUB	138.00	138.00	1	0.17	0.00	1	795 ACSR
150	TL81-539 MCALESTER SOUTH SUB	LONE OAK SUB	138.00	138.00	1	13.30	0.00	1	556.50 ACSR
151	TL81-539 MCALESTER SOUTH SUB	LONE OAK SUB	138.00	138.00	1	0.16		1	795 ACSR
152	TL81-539A MCALESTER SOUTH TAP	-	138.00	138.00	1	5.73	0.00	1	795 ACSR
153	TL81-540 LAWTON EASTSIDE	SHERIDAN ROAD	138.00	138.00	1	7.17		1	1272.0 ACSR
154	TL81-540 LAWTON EASTSIDE	SHERIDAN ROAD	138.00	138.00	1	0.35		2	1272.0 ACSR & 477 ACSR
155	TL81-541 LAWTON SHERIDAN ROAD	LAWTON 112TH & W GORE	138.00	138.00	1	7.06	0.00	1	477.0 ACSR
156	TL81-541A (RADIAL) LAWTON WESTSIDE NORTH TAP		138.00	138.00	1	1.50		1	477.0 ACSR
157	TL81-542 LAWTON 112TH W GORE	SNYDER	138.00	138.00	1	0.56		1	795 ACSR
158	TL81-542 LAWTON 112TH W GORE	SNYDER	138.00	138.00	2	19.00		1	795 ACSR
159	TL81-542A (RADIAL) CACHE TAP		138.00	138.00	1	0.04		1	795 ACSR
160	TL81-542B (RADIAL) LAWTON AIR PRODUCTS TAP		138.00	138.00	1	0.60		1	477.0 ACSR
161	TL81-543 (RADIAL) LAWTON 112TH & W. GORE	GOODYEAR 138KV LINE	138.00	138.00	1	0.59	0.00	0	477.0 ACSR
162	TL81-544 RIVERSIDE PLANT SUB	KIMBERLY CLARK SUB 138kV LINE	138.00	138.00	1	0.74	0.00	2	1272.0 ACSR
163	TL81-544 RIVERSIDE PLANT SUB	KIMBERLY CLARK SUB 138kV LINE	138.00	138.00	1	1.57	0.00	1	1272 ACSR
164	TL81-544 RIVERSIDE PLANT SUB	KIMBERLY CLARK SUB 138kV LINE	138.00	138.00	3	0.31	0.00	2	1272 ACSR
165	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	0.09	0.00	1	1272 ACSR
166	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	1.91	0.00	1	477.0 ACSR
167	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	2	30.00	0.00	1	1272.0 ACSR
168	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	4.36	0.00	1	1272.0 ACSR
169	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	5.54	0.00	1	(T2) 636 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
170	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	0.13	0.00	2	T2 636 ACSR AND 795 ACSR
171	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	0.68	0.00	2	1272 ACSR AND 397.5 ACSR
172	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	0.40	0.00	2	1272 ACSR and 795 ACSR
173	TL81-545 NORTHEASTERN POWER STATION	VINITA JUNCTION 138kV LINE	138.00	138.00	1	2.70	0.00	2	1272 ACSR AND 477 ACSR
174	TL81-545A (RADIAL) HAWTHORNE TAP		138.00	138.00	1	0.18	0.00	1	477 ACSR
175	TL81-545B (RADIAL) ALLUWE SHELL TAP		138.00	138.00	2	0.30	0.00	1	1272 ACSR
176	TL81-545B (RADIAL) ALLUWE SHELL TAP		138.00	138.00	2	1.67	0.00	1	477 ACSR
177	TL81-546 PRYOR JCT SUB	MAID SUB	138.00	138.00	1	0.63	0.00	1	1272.0 ACSR
178	TL81-546 PRYOR JCT SUB	MAID SUB	138.00	138.00	2	5.67	0.00	1	1272.0 ACSR
179	TL81-546A (RADIAL) ELKEM MIDWEST CABIDE TAP		138.00	138.00	2	0.06	0.00	1	1272.0 ACSR
180	TL81-547 CATOOSA SUB	AMERICAN AIRLINES SUB	138.00	138.00	1	3.81	0.00	1	1272.0 ACSR
181	TL81-547 CATOOSA SUB	AMERICAN AIRLINES SUB	138.00	138.00	2	5.44	0.00	1	(T2) 636 ACSR
182	TL81-548 TULSA NORTH	AMERICAN AIRLINES 138kV	138.00	138.00	1	0.33	0.00	2	1272.0 ACSR and 636 ACSR
183	TL81-548 TULSA NORTH	AMERICAN AIRLINES 138kV	138.00	138.00	2	3.16	0.00	1	1272 ACSR
184	TL81-548 TULSA NORTH	AMERICAN AIRLINES 138kV	138.00	138.00	1	7.25	0.00	1	1272 ACSR
185	TL81-548A (RADIAL) CHEROKEE DATA CENTER WEST TAP		138.00	138.00	1	1.00	0.00	1	(T2) 397 ACSR
186	TL81-549 NOWATA SUB	BARTLESVILLE SOUTHEAST	138.00	138.00	1	14.36	0.00	1	(T2) 397 ACSR
187	TL81-550 TULSA PLANT	RIVERSIDE PLANT 138kV	138.00	138.00	1	0.17	0.00	2	1272 ACSR and 795 ACSR
188	TL81-550 TULSA PLANT	RIVERSIDE PLANT 138kV	138.00	138.00	2	1.14	0.00	1	T2 636 ACSR
189	TL81-550 TULSA PLANT	RIVERSIDE PLANT 138kV	138.00	138.00	1	1.11	0.00	1	T2 636 ACSR
190	TL81-550 TULSA PLANT	RIVERSIDE PLANT 138kV	138.00	138.00	1	4.67	0.00	1	1272 ACSR
191	TL81-550A (RADIAL) OAKS 138kV		138.00	138.00	1	3.04	0.00	1	4/0 ACSR (PENGUIN)
192	TL81-551 KIMBERLY CLARK	BIXBY 111TH 138kV	138.00	138.00	1	4.69	0.00	1	1272.0 ACSR
193	TL81-551 KIMBERLY CLARK	BIXBY 111TH 138kV	138.00	138.00	3	0.71	0.00	1	1272 ACSR
194	TL81-551 KIMBERLY CLARK	BIXBY 111TH 138kV	138.00	138.00	1	1.40	0.00	2	1272 ACSR
195	TL81-553 TULSA SOUTHEAST	ONETA	138.00	138.00	1	2.26	0.00	1	1272.0 ACSR
196	TL81-553A (RADIAL) 77TH MEMORIAL TAP		138.00	138.00	1	1.30	0.00	1	477 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
197	TL81-553B (RADIAL) 53RD & GARNETT TAP		138.00	138.00	1	0.70	0.00	2	(T2) 4/0, 6/1 and 477 ACSR
198	TL81-554 PRYOR JCT SUB	GROVE	138.00	138.00	1	2.22	0.00	1	795 ACSR
199	TL81-554 PRYOR JCT SUB	GROVE	138.00	138.00	2	14.06	0.00	1	795 ACSR
200	TL81-554 PRYOR JCT SUB	GROVE	138.00	138.00	2	32.00	0.00	1	(T2) 397.0 ACSR
201	TL81-554 PRYOR JCT SUB	GROVE	138.00	138.00	1	0.52	0.00	2	795 ACSR
202	TL81-554 PRYOR JCT SUB	GROVE	138.00	138.00	1	0.30	0.00	2	(T2) 397 ACSR
203	TL81-554A JAY TAP		138.00	138.00	1	0.16	0.00	2	795 ACSR
204	TL81-556 TULSA SOUTHEAST SUB	EAST 61ST SUB	138.00	138.00	1	0.14	0.00	1	1272.0 ACSR
205	TL81-556 TULSA SOUTHEAST SUB	EAST 61ST SUB	138.00	138.00	1	1.69	0.00	2	1272.0 ACSR
206	TL81-556 TULSA SOUTHEAST SUB	EAST 61ST SUB	138.00	138.00	1	1.80	0.00	1	1272.0 ACSR (54/19)
207	TL81-557 VINITA JCT SUB	HOCKERVILLE SUB (EDE)	138.00	138.00	1	3.51	0.00	1	795 ACSR
208	TL81-557 VINITA JCT SUB	HOCKERVILLE SUB (EDE)	138.00	138.00	1	1.19	0.00	1	(T2) 397 ACSR
209	TL81-557 VINITA JCT SUB	HOCKERVILLE SUB (EDE)	138.00	138.00	2	12.30	0.00	1	(T2) 397 ACSR
210	TL81-557 VINITA JCT SUB	HOCKERVILLE SUB (EDE)	138.00	138.00	2	17.52	0.00	1	795 ACSR
211	TL81-559 BARTLESVILLE SOUTHEAST SUB	BARTLESVILLE COMANCHE SUB	138.00	138.00	1	0.08	0.00	1	795 ACSR
212	TL81-559 BARTLESVILLE SOUTHEAST SUB	BARTLESVILLE COMANCHE SUB	138.00	138.00	1	3.28	0.00	1	636.0 ACSR
213	TL81-559 BARTLESVILLE SOUTHEAST SUB	BARTLESVILLE COMANCHE SUB	138.00	138.00	1	0.04	0.00	2	477 ACSR and 477 ACSR
214	TL81-559 BARTLESVILLE SOUTHEAST SUB	BARTLESVILLE COMANCHE SUB	138.00	138.00	1	0.03	0.00	2	477 ACSR and 4/0 ACSR 6/1
215	TL81-560 ONETA SUB	81ST & GARNETT SUB	138.00	138.00	1	8.19	0.00	1	(T2) 636 ACSR
216	TL81-560 ONETA SUB	81ST & GARNETT SUB	138.00	138.00	1	9.33	0.00	1	1272 ACSR
217	TL81-560A (RADIAL) 121ST & LYNN LANE TAP		138.00	138.00	1	0.02	0.00	1	1272 ACSR
218	TL81-561 CRAIG JCT.	IDABEL	138.00	138.00	1	0.15	0.00	1	1272 ACSR
219	TL81-561 CRAIG JCT.	IDABEL	138.00	138.00	2	11.58	0.00	1	795 ACSR/SD
220	TL81-561 CRAIG JCT.	IDABEL	138.00	138.00	1	2.00	0.00	1	795 ACSR
221	TL81-561 CRAIG JCT.	IDABEL	138.00	138.00	2	3.63	0.00	1	795 ACSR
222	TL81-561 CRAIG JCT.	IDABEL	138.00	138.00	2	0.50	0.00	2	795 ACSR AND 795 ACSR
223	TL81-561A (RADIAL) BROKEN BOW TAP		138.00	138.00	1	2.30	0.00	1	477 ACSR
224	TL81-562 MOHAWK	AMERICAN AIRLINES	138.00	138.00	1	4.49	0.00	1	1272.0 ACSR
225	TL81-562 MOHAWK	AMERICAN AIRLINES	138.00	138.00	2	1.55	0.00	1	1272 ACSR
226	TL81-563 96TH AND YALE SUB	EAST 61ST ST SUB 138kV	138.00	138.00	2	2.87	0.00	1	1272.0 ACSR/AW
227	TL81-563 96TH AND YALE SUB	EAST 61ST ST SUB 138kV	138.00	138.00	1	2.32	0.00	1	1272 ACSR/AW

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
228	TL81-563 96TH AND YALE SUB	EAST 61ST ST SUB 138kV	138.00	138.00	1	0.40	0.00	2	1272 ACSR/AW 477 ACSR
229	TL81-564 DELAWARE SUB	KANSAS STATE LINE 138KV	138.00	138.00	1	15.54	0.00	1	1272.0 ACSR
230	TL81-565 COMANCHE	112TH & W. GORE	138.00	138.00	1	19.69	0.00	1	(T2) 636 ACSR
231	TL81-566 BROKEN ARROW 81ST STREET SUB	FORD GLASS PLANT SUB 138KV	138.00	138.00	1	3.06	0.00	1	795.0 ACSR
232	TL81-568 AMERICAN AIRLINES	MINGO ROAD AIRPORT	138.00	138.00	1	0.93	0.38	0	1272.0 ACSR
233	TL81-579 HENRYETTA	WELEETKA (TLN114:00567)	138.00	138.00	1	13.33	0.00	1	1272.0 ACSR
234	TL81-600 CARSON TAP NORTH		138.00	138.00	1	0.10	0.00	1	1233.6 ACSR/TW
235	TL81-612 MCALESTER CITY BUS TIE		69.00	138.00	1	0.04	0.00	0	795 ACSR
236	TL81-616 Craig Junction	Hugo (WFEC)	138.00	138.00	1	0.24	0.00	1	1272 ACSR
237	TL81-622 Wildhorse	Wildcat 138kV Tie Line	138.00	138.00	1	0.10	0.00	1	T2 477 ACSR
238	TL81-634 RIVERSIDE	RS PEAKER	138.00	138.00	1	0.20	0.00	1	795 ACSR
239	TL81-641 WELEETKA GEN TIE		138.00	138.00	1	0.07	0.00	1	795 ACSR
240	TL81-802 WELEETKA PLANT	RIVERSIDE PLANT (TLN114:0802A)	138.00	138.00	3	2.62	0.00	1	795.0 ACSR
241	TL81-802 WELEETKA PLANT	RIVERSIDE PLANT (TLN114:0802)	138.00	138.00	1	28.31	1.90	0	1272.0 ACSR
242	TL81-803 SOUTHWESTERN POWER STATION	ANADARKO (WFEC)	138.00	138.00	2	7.37	0.00	1	795.0 ACSR
243	TL81-804 SOUTHWESTERN PLANT	NORGE ROAD	138.00	138.00	2	0.22	0.00	1	397.5 ACSR
244	TL81-805 WELEETKA PLANT	OKMULGEE	138.00	138.00	3	0.05	0.00	1	795 ACSR
245	TL81-806 SAND SPRINGS SUB	WILDHORSE SUB 138kV	138.00	138.00	1	1.80	0.00	2	795 ACSR & 1272 ACSR
246	TL81-806 SAND SPRINGS SUB	WILDHORSE SUB 138kV	138.00	138.00	2	15.55	0.00	1	795 ACSR
247	TL81-806 SAND SPRINGS SUB	WILDHORSE SUB 138kV	138.00	138.00	1	5.90	0.00	1	T2 477 ACSR
248	TL81-806A HIGHWAY 20 TAP		138.00	138.00	1	6.10	0.00	1	T2 477 ACSR
249	TL81-806B (RADIAL) HOMINY TAP		138.00	138.00	1	5.40	0.00	1	T2 477 ACSR
250	TL81-806C (RADIAL) 81-806 TAP (11/2) 81-843 EMERGENCY CON		138.00	138.00	1	1.21	0.00	1	266.8 ACSR
251	TL81-807 ONETA	TULSA SOUTHEAST	138.00	138.00	3	9.18	0.00	2	1026 ACCC AND T2 795 ACSR
252	TL81-807 ONETA	TULSA SOUTHEAST	138.00	138.00	3	5.64	0.00	2	795 ACSR AND T2 397.5 ACSR
253	TL81-807 ONETA	TULSA SOUTHEAST	138.00	138.00	2	0.83	0.00	2	T2 397.5 ACSR
254	TL81-807 ONETA	TULSA SOUTHEAST	138.00	138.00	1	0.47	0.00	1	477 ACSR
255	TL81-807 ONETA	TULSA SOUTHEAST	138.00	138.00	1	2.32	0.00	2	(T2) 795 ACSR T2 397.5 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
256	TL81-807A (RADIAL) BROKEN ARROW NORTH TAP		138.00	138.00	1	0.29	0.00	1	477 ACSR
257	TL81-807A (RADIAL) BROKEN ARROW NORTH TAP		138.00	138.00	2	2.95	0.00	1	477 ACSR
258	TL81-808 TULSA PLANT SUB	SAND SPRINGS SUB	138.00	138.00	3	2.34	0.00	2	T2 636 ACSR
259	TL81-808 TULSA PLANT SUB	SAND SPRINGS SUB	138.00	138.00	3	1.20	0.00	2	T2 636 ACSR AND 556.5 ACSR
260	TL81-808 TULSA PLANT SUB	SAND SPRINGS SUB	138.00	138.00	3	4.15	0.00	2	556.5 ACSR
261	TL81-808 TULSA PLANT SUB	SAND SPRINGS SUB	138.00	138.00	1	0.32	0.00	2	T2 636 ACSR AND 556.5 ACSR
262	TL81-808 TULSA PLANT SUB	SAND SPRINGS SUB	138.00	138.00	1	0.10	0.00	2	1590 ACSR
263	TL81-808 TULSA PLANT SUB	SAND SPRINGS SUB	138.00	138.00	1	0.07	0.00	2	1272 ACSR
264	TL81-808A (RADIAL) 12TH & CARSON SOUTH TAP		138.00	138.00	1	6.82	0.00	0	2x795.0 ACSR
265	TL81-808B (RADIAL) UNION AVENUE REFINERY								
266	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	2	1.57	0.00	3	T2 795 ACSR
267	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	1	0.31	0.00	3	T2 795 ACSR
268	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	1	1.08	0.00	2	T2 795 ACSR
269	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	2	0.65	0.00	1	T2 397.5 ACSR
270	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	1	1.18	0.00	1	1272 ACSR
271	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	1	1.40	0.00	1	T2 795 ACSR
272	TL81-809 RIVERSIDE POWER	SOUTH HUDSON 138kV	138.00	138.00	2	4.02	0.00	1	1272 ACSR
273	TL81-809A (RADIAL) 81ST & YALE TAP		138.00	138.00	2	0.45	0.00	1	266.8 ACSR
274	TL81-809B (RADIAL) SOUTHERN HILLS TAP		138.00	138.00	1	1.10	0.00	1	477.0 ACSR
275	TL81-809D (RADIAL) WARREN MEDICAL TAP		138.00	138.00	1	0.25	0.00	1	477 ACSR
276	TL81-809D (RADIAL) WARREN MEDICAL TAP		138.00	138.00	1	0.23	0.00	1	400 MCM_UNDERGROUND
277	TL81-809E (RADIAL) ORAL ROBERTS TAP		138.00	138.00	1	0.68	0.00	1	477 ACSR
278	TL81-810 TULSA SOUTHEAST SUB	CATOOSA SUB	138.00	138.00	3		1.48	2	1026 ACCC
279	TL81-810 TULSA SOUTHEAST SUB	CATOOSA SUB	138.00	138.00	3		4.16	2	T2 397.5 ACSR
280	TL81-810 TULSA SOUTHEAST SUB	CATOOSA SUB	138.00	138.00	3		2.51	2	1026 ACCC and 954 ACSR
281	TL81-810 TULSA SOUTHEAST SUB	CATOOSA SUB	138.00	138.00	4		1.83	2	556.5 ACSR and 954 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
282	TL81-810 TULSA SOUTHEAST SUB	CATOOSA SUB	138.00	138.00	2		0.83	2	T2 397.5 ACSR
283	TL81-810 TULSA SOUTHEAST SUB	CATOOSA SUB	138.00	138.00	1		0.47	2	T2 397.5 ACSR
284	TL81-810B (RADIAL) 21ST STREET TAP		138.00	138.00	1	1.34	0.00	1	556.5 ACSR
285	TL81-810B (RADIAL) 21ST STREET TAP		138.00	138.00	1	0.50	0.00	1	795 ACSR
286	TL81-810C (RADIAL) 15TH & FULTON TAP		138.00	138.00	1	0.50	0.00	1	556.5 ACSR
287	TL81-810C (RADIAL) 15TH & FULTON TAP		138.00	138.00	1	2.35			477 ACSR
288	TL81-810D (RADIAL) LYNN LANE TAP		138.00	138.00	1	1.00	0.00	1	477 ACSR
289	TL81-811 WEKIWA	SAND SPRINGS SUB 138	138.00	138.00	3	0.67	0.00	1	636 ACSR
290	TL81-811 WEKIWA	SAND SPRINGS SUB 138	138.00	138.00	1	0.10	0.00	1	1272 ACSR
291	TL81-811 WEKIWA	SAND SPRINGS SUB 138	138.00	138.00	3	0.14	0.00	2	636 ACSR
292	TL81-811 WEKIWA	SAND SPRINGS SUB 138	138.00	138.00	3	2.12	0.00	1	636 ACSR
293	TL81-812A OAKS TAP		138.00	138.00	1	2.44	0.00	1	477.0 ACSR
294	TL81-813 SAND SPRINGS SUB	ARMCO STEEL	138.00	138.00	1	0.14	0.00	2	1272.0 ACSR
295	TL81-814 NORTHEASTERN POWER STATION	TULSA NORTH 138	138.00	138.00	3	12.36	0.00	2	636 ACSR
296	TL81-814 NORTHEASTERN POWER STATION	TULSA NORTH 138	138.00	138.00	2	0.21	0.00	2	1272 ACSR
297	TL81-814 NORTHEASTERN POWER STATION	TULSA NORTH 138	138.00	138.00	1	0.81	0.00	2	636 ACSR
298	TL81-814A (RADIAL) OWASSO 86TH STREET TAP		138.00	138.00	1	0.51	0.00	0	477 ACSR
299	TL81-814B (RADIAL) OWASSO 109TH STREET TAP		138.00	138.00	1	0.24	0.00	1	795 ACSR
300	TL81-815 NORTHEASTERN POWER	NOWATA	138.00	138.00	2	0.31	0.00	2	795.0 ACSR AND 477 ACSR
301	TL81-815 NORTHEASTERN POWER	NOWATA	138.00	138.00	2	19.80	0.00	1	795 ACSR
302	TL81-815 NORTHEASTERN POWER STATION	NOWATA	138.00	138.00	1	0.11	0.00	1	1272 ACSR
303	TL81-816 NORTHEASTER POWER STATION	BARTLESVILLE SOUTHEAST	138.00	138.00	3	0.14	0.00	2	1272.0 ACSR
304	TL81-816 NORTHEASTER POWER STATION	BARTLESVILLE SOUTHEAST	138.00	138.00	3	0.07	0.00	2	1272.0 ACSR 556.5 ACSR
305	TL81-816 NORTHEASTER POWER STATION	BARTLESVILLE SOUTHEAST	138.00	138.00	3	0.71	0.00	2	1272.0 ACSR and 795 ACSR
306	TL81-816 NORTHEASTER POWER STATION	BARTLESVILLE SOUTHEAST	138.00	138.00	1	23.38	0.00	1	1272.0 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
307	TL81-817 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	1	3.35	0.00	1	477.0 ACSR
308	TL81-817B CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	1	0.03	0.00	1	477 ACSR
309	TL81-818 SAND SPRINGS SUB	OG&E INTERCONNECT	138.00	138.00	2	1.76	0.00	1	795 ACSR
310	TL81-818 SAND SPRINGS SUB	OG&E INTERCONNECT	138.00	138.00	3	0.83	0.00	1	795 ACSR
311	TL81-818 SAND SPRINGS SUB	OG&E INTERCONNECT	138.00	138.00	1	0.15	0.00	1	795 ACSR
312	TL81-818A (RADIAL) PRATTVILLE TAP		138.00	138.00	1	0.10	0.00	1	1926 ACSR TYPE 13
313	TL81-818A (RADIAL) PRATTVILLE TAP		138.00	138.00	1	0.10	0.00	2	1927 ACSR TYPE 13
314	TL81-819 SOUTHWESTERN PLANT	HOBART JCT SUB	138.00	138.00	1	0.10	0.00	2	T2 477 ACSR and 795 ACSR
315	TL81-819 SOUTHWESTERN PLANT	HOBART JCT SUB	138.00	138.00	1	16.17	0.00	1	T2 477 ACSR
316	TL81-819 SOUTHWESTERN PLANT	HOBART JCT SUB	138.00	138.00	1	0.22	0.00	1	397 ACSR
317	TL81-819A (RADIAL) CARNEGIE TAP		138.00	138.00	1	0.03	0.00	1	477 ACSR
318	TL81-820 ALTUS JCT	RUSSELL (WFEC) (TLN114:0820)	138.00	138.00	2	32.90	0.00	1	477.0 ACSR
319	TL81-820 ALTUS JCT	RUSSELL (WFEC) (TLN114:0820)	138.00	138.00	1	7.10	0.00	2	795 ACSR
320	TL81-820 ALTUS JCT	RUSSELL (WFEC) (TLN114:0820A)	138.00	138.00	2	3.85	0.00	1	477.0 ACSR
321	TL81-821 CORNVILLE SUB	DUNCAN SUB W/TAP	138.00	138.00	1	0.06	0.00	1	1272 ACSR
322	TL81-821 CORNVILLE SUB	DUNCAN SUB W/TAP	138.00	138.00	1	16.70	0.00	1	795 ACSR
323	TL81-821 CORNVILLE SUB	DUNCAN SUB W/TAP	138.00	138.00	1	0.41	0.00	1	1533.3 ACSR TYPE 13
324	TL81-821 CORNVILLE SUB	DUNCAN SUB W/TAP	138.00	138.00	2	24.00	0.00	1	266.8 ACSR
325	TL81-821 CORNVILLE SUB	DUNCAN SUB W/TAP	138.00	138.00	2	0.86	0.00	1	477 ACSR
326	TL81-821A (RADIAL) RUSH SPRINGS CHESTNUT STREET TAP		138.00	138.00	1	2.04	0.00	1	477 ACSR
327	TL81-821B RUSH SPRINGS NATURAL GAS TAP		138.00	138.00	1	0.25	0.00	1	1533.3 ACSR TYPE 13
328	TL81-821B RUSH SPRINGS NATURAL GAS TAP		138.00	138.00	1	6.74	0.00	1	T2 397.5 ACSR
329	TL81-823 SWPA INTERCONNECT TUPELO SUB	ATOKA SUB	138.00	138.00	2	24.70	0.00	1	477.0 ACSR
330	TL81-823A (RADIAL) COALGATE PUMP TAP		138.00	138.00	2	0.60	0.00	1	477.0 ACSR
331	TL81-823C (RADIAL) ALLEN TRANSOK TAP		138.00	138.00	2	8.30	0.00	1	477.0 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
332	TL81-823CA EXPLORER COALGATE PUMP STATION TAP		138.00	138.00	2	0.18	0.00	1	477.0 ACSR
333	TL81-824 MARKHAM FERRY SUB	PRYOR SUB W/TAP LONE STAR	115.00	138.00	2	7.66	0.00	1	556.5 ACSR
334	TL81-824 MARKHAM FERRY SUB	PRYOR SUB W/TAP LONE STAR	115.00	138.00	1	2.64	0.00	1	795 ACSR
335	TL81-824A (RADIAL) LONE STAR		138.00	138.00	2	0.16	0.00	1	556.5 ACSR
336	TL81-825 SOUTHWESTERN PLANT SUB	LAWTON EASTSIDE SUB	138.00	138.00	1	0.12	0.00	1	795 ACSR
337	TL81-825 SOUTHWESTERN PLANT SUB	LAWTON EASTSIDE SUB	138.00	138.00	2	35.90	0.00	1	795 ACSR
338	TL81-825 SOUTHWESTERN PLANT SUB	LAWTON EASTSIDE SUB	138.00	138.00	1	0.10	0.00	2	795 ACSR
339	TL81-826 (RADIAL) SOUTH COFFEYVILLE TAP		138.00	138.00	1	6.00	0.00	1	1590 ACSR
340	TL81-826 BARTLESVILLE SOUTHEAST SUB	KG&E INTERCONNECT	138.00	138.00	1	0.03	0.00	1	T2 795 ACSR
341	TL81-826 BARTLESVILLE SOUTHEAST SUB	KG&E INTERCONNECT	138.00	138.00	1	1.35	0.00	2	795 ACSR and T2 795 ACSR
342	TL81-826 BARTLESVILLE SOUTHEAST SUB	KG&E INTERCONNECT	138.00	138.00	1	5.87	0.00	2	796 ACSR and 1590 ACSR
343	TL81-826 BARTLESVILLE SOUTHEAST SUB	KG&E INTERCONNECT	138.00	138.00	1	15.00	0.00	1	1590 ACSR
344	TL81-827 BARTLESVILLE SOUTHEAST SUB	SHIDLER SUB W/TAP COMMERCE	138.00	138.00	1	0.14	0.00	1	795 ACSR
345	TL81-827(RADIAL) 81-827 TAP - 81-558 EMERGENCY CONNECTION		138.00	138.00	2	4.31	0.00	1	477 ACSR
346	TL81-828 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	2	8.17	0.00	1	795 ACSR
347	TL81-828 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	3	0.73	0.00	1	795.0 ACSR
348	TL81-828 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	1	12.61	0.00	1	795.0 ACSR
349	TL81-828 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	1	0.64	0.00	2	795.0 ACSR
350	TL81-828 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	3	0.34	0.00	2	795.0 ACSR
351	TL81-828 CATOOSA	NORTHEASTERN POWER STATION	138.00	138.00	3	0.06	0.00	2	795.0 ACSR and 636 ACSR
352	TL81-828A (RADIAL) TERRA NITROGEN TAP		138.00	138.00	1	1.30	0.00	1	477 ACSR
353	TL81-828B (RADIAL) PORT OF CATOOSA		138.00	138.00	1	1.97	0.00	1	477 ACSR
354	TL81-828C (RADIAL) TRANSCO CLAREMORE 138kV Tap		138.00	138.00	1	0.16	0.00	1	T2 4/0 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
355	TL81-828C (RADIAL) TRANSCO CLAREMORE 138kV Tap		138.00	138.00	1	0.58	0.00	1	795 ACSR
356	TL81-829 CATOOSA SUB	TULSA NORTH SUB W/TAP CHEROKEE INDUSTRIAL PARK	138.00	138.00	1	0.36	0.00	1	636.0 ACSR
357	TL81-829 CATOOSA SUB	TULSA NORTH SUB W/TAP CHEROKEE INDUSTRIAL PARK	138.00	138.00	3	16.60	0.00	2	556.5 ACSR and 636 ACSR
358	TL81-829 CATOOSA SUB	TULSA NORTH SUB W/TAP CHEROKEE INDUSTRIAL PARK	138.00	138.00	1	0.37	0.00	1	556.5 ACSR
359	TL81-829B (RADIAL) CHEROKEE INDUSTRIAL PARK TAP		138.00	138.00	1	2.20	0.00	1	795 ACSR
360	TL81-833 CORNVILLE SUB	OG&E INTERCONNECT (CIMMARON SUBSTATION)	138.00	138.00	1	0.25	0.00	1	1272.0 ACSR
361	TL81-833 CORNVILLE SUB	OG&E INTERCONNECT (CIMMARON SUBSTATION)	138.00	138.00	1	0.34	0.00	1	1590 ACSR
362	TL81-833 CORNVILLE SUB	OG&E INTERCONNECT (CIMMARON SUBSTATION)	138.00	138.00	1	0.15	0.00	1	795 ACSR
363	TL81-833 CORNVILLE SUB	OG&E INTERCONNECT (CIMMARON SUBSTATION)	138.00	138.00	2	16.52	0.00	1	795 ACSR
364	TL81-833A (RADIAL) TUTTLE CONOCO TAP		138.00	138.00	1	4.78	0.00	1	266.8 ACSR
365	TL81-836 RED OAK	EUFAULA (SWPA)	138.00	138.00	1	16.51	0.00	0	4/0 ACSR
366	TL81-836 RED OAK	EUFAULA (SWPA)	0.00	0.00	2	26.59	0.00	0	477.0 ACSR
367	TL81-836 RED OAK	EUFAULA (SWPA)	0.00	0.00	3	0.84	0.00	0	556.5 ACSR
368	TL81-836 RED OAK	EUFAULA (SWPA)	0.00	0.00	0	0.00	0.00	0	795.0 ACSR
369	TL81-837 OKMULGEE SUB	RIVERSIDE PLANT	138.00	138.00	2	26.00	1.90	1	795.0 ACSR
370	TL81-838 CATOOSA	ONETA SUB w/TAP BROKEN ARROW SUB	138.00	138.00	3	1.41	0.00	2	954 ACSR and 556.5 ACSR
371	TL81-838 CATOOSA	ONETA SUB w/TAP BROKEN ARROW SUB	138.00	138.00	3	0.95	0.00	2	954 ACSR
372	TL81-838 CATOOSA	ONETA SUB w/TAP BROKEN ARROW SUB	138.00	138.00	3	2.50	0.00	2	954 ACSR and 1026 ACCC
373	TL81-838 CATOOSA	ONETA SUB w/TAP BROKEN ARROW SUB	138.00	138.00	1	0.10	0.00	1	795 ACSR
374	TL81-838 CATOOSA	ONETA SUB w/TAP BROKEN ARROW SUB	138.00	138.00	1	0.44	0.00	1	1590 ACSR
375	TL81-838A (RADIAL) BROKEN ARROW NORTH TAP		138.00	138.00	1	0.53	0.00	1	477 ACSR
376	TL81-838A (RADIAL) BROKEN ARROW NORTH TAP		138.00	138.00	1	3.45	0.00	1	477 ACSR
377	TL81-838B (RADIAL) 21ST & EAST AVENUE TAP		138.00	138.00	1	7.60	0.00	1	556.5 ACSR
378	TL81-838B (RADIAL) 21ST & EAST AVENUE TAP		138.00	138.00	1	0.03	0.00	1	1590 ACSR
379	TL81-838D LYNN LANE TAP		138.00	138.00	1	1.01	0.00	1	795 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
380	TL81-840 LAWTON EASTSIDE	DUNCAN W/TAP COMANCHE	138.00	138.00	2	21.70	0.00	1	266.8 ACSR
381	TL81-841 SOUTHWESTERN PLANT	CORNVILLE	138.00	138.00	1	0.49	0.00	0	1272.0 ACSR
382	TL81-841 SOUTHWESTERN PLANT	CORNVILLE	138.00	138.00	2	2.00	0.00	0	795.0 ACSR
383	TL81-841C Verden Natural Gas Tap		138.00	138.00	1	0.35	0.00	1	T2 477 ACSR
384	TL81-843 TULSA NORTH SUB	BARTLESVILLE SUB	138.00	138.00	2	10.93	0.00	1	795.0 ACSR
385	TL81-843 TULSA NORTH SUB	BARTLESVILLE SUB	138.00	138.00	1	5.37	0.00	1	795 ACSR
386	TL81-844 BARTLESVILLE MOUNDS ROAD SUB	BARTLESVILLE COMANCHE	138.00	138.00	2	2.90	0.00	1	795.0 ACSR
387	TL81-844 BARTLESVILLE MOUNDS ROAD SUB	BARTLESVILLE COMANCHE	138.00	138.00	1	0.00	0.97	2	T2 636 ACSR
388	TL81-845 (WFEC) INTERCONNECT RUSSELL SUB	WTU INTERCONNECT TREXAS STATE LINE	138.00	138.00	1	7.13	0.00	2	795 ASCSR
389	TL81-845 (WFEC) INTERCONNECT RUSSELL SUB	WTU INTERCONNECT TREXAS STATE LINE	138.00	138.00	2	15.83	0.00	1	477.0 ACSR
390	TL81-845 (WFEC) INTERCONNECT RUSSELL SUB	WTU INTERCONNECT TREXAS STATE LINE	138.00	138.00	3	0.97	0.00	1	477.0 ACSR
391	TL81-846 MOHAWK	TULSA NORTH 138	138.00	138.00	1	7.00	0.00	1	477.0 ACSR
392	TL81-846A (RADIAL) PINE & PEORIA TAP		138.00	138.00	1	3.46	0.00	1	477.0 ACSR
393	TL81-846B (RADIAL) 46TH STREET NORTH (EAST) TAP		138.00	138.00	1	0.83	0.00	1	477.0 ACSR
394	TL81-846B (RADIAL) YALE & ARCHER TAP		138.00	138.00	1	3.71	0.00	1	477.0 ACSR
395	TL81-847 CRAIG JCT SUB	(SWEPCO) INTERCONNECT ARKANSAS	138.00	138.00	1	2.25	0.00	2	1590.0 ACSR
396	TL81-847 CRAIG JCT SUB	(SWEPCO) INTERCONNECT ARKANSAS	138.00	138.00	1	9.30	0.00	1	1272 ACSR
397	TL81-848 SOUTHWESTERN PLANT	LAWTON EASTSIDE SUB	138.00	138.00	1	0.78	0.00	1	795 ACSR
398	TL81-848 SOUTHWESTERN PLANT	LAWTON EASTSIDE SUB	138.00	138.00	2	36.80	0.00	1	795 ACSR
399	TL81-848 SOUTHWESTERN PLANT	LAWTON EASTSIDE SUB	138.00	138.00	1	2.00	0.00	1	2x397.5 ACSR
400	TL81-848A (RADIAL) FLETCHER TEMPLE EASTEX TAP		138.00	138.00	1	1.12	0.00	1	477 ACSR
401	TL81-849 OKMULGEE	HENRYETTA	138.00	138.00	1	13.64	0.16	0	1272.0 ACSR
402	TL81-851 SAPULPA ROAD 138kV EAST LOOP		138.00	138.00	1	5.03	0.00	2	T2 636 ACSR
403	TL81-852 SAPULPA ROAD 138kV NORTH LOOP		138.00	138.00	1	5.20	0.00	2	1272 ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
404	TL81-853 ALTUS JUNCTION	SNYDER	138.00	138.00	1	25.20	0.00	1	T2 397
405	TL81-853 ALTUS JUNCTION	SNYDER	138.00	138.00	1	0.50	0.00	2	T2 397 AND 795 ACSR
406	SubTotal 138 kV Lines in OK		0.00	0.00		1,506.72	129.05	0	
407	TL81-531 (RADIAL) HOLLIS TAP (WTU)	HOLLIS (INTERCONNECT-OK PORTION)	138.00	138.00	1	5.33	0.00	1	477.0 ACSR
408	SubTotal 138 kV Lines in TX		0.00	0.00		5.33	0.00	0	
409	TL66-610A TOSCO REFINERY	138KV TAP	69.00	138.00	1	1.25	0.00	1	1272 ACSR
410	TL66-622B THOMAS CITY	138KV TAP	69.00	138.00	1	18.11	0.00	1	477 ACSR
411	TL81-504 CRAIG JCT SUB	SWPA INTERCONNECT-BROKEN BOW	138.00	138.00	1	7.88	0.00	1	795.0 ACSR
412	TL81-504 CRAIG JCT SUB	SWPA INTERCONNECT-BROKEN BOW	138.00	138.00	2	1.37	0.00	1	795.0 ACSR
413	TL81-504 CRAIG JCT SUB	SWPA INTERCONNECT-BROKEN BOW	138.00	138.00	1	0.00	2.14	2	1590 ACSR
414	TL81-504 CRAIG JCT SUB	SWPA INTERCONNECT-BROKEN BOW	138.00	138.00	1	0.15	0.00	1	1590 ACSR
415	TL81-552 BARNSDALL SUB	MOUNDS ROAD SUB	138.00	138.00	2	14.86	0.00	1	795.0 ACSR
416	TL81-552 BARNSDALL SUB	MOUNDS ROAD SUB	138.00	138.00	1	0.40	0.00	1	795.0 ACSR
417	TL81-552 BARNSDALL SUB	MOUNDS ROAD SUB	138.00	138.00	1	2.40	0.00	2	1272.0 ACSR
418	TL81-589 TIPTON TAP		69.00	138.00	1	9.44	0.00	1	1272 ACSR
419	TL81-598 BROKEN ARROW	WATER PLANT TAP	69.00	138.00	1	3.11	0.00	1	1272 ACSR
420	TL81-599 COWETA JUNCTION	TAP	69.00	138.00	1	5.47	0.00	1	1272 ACSR
421	TL81-606 TALAWANDA	MCALESTER INDUSTRIAL	138.00	138.00	1	8.80	0.00	1	1533 ACSR
422	TL81-608 GRADY 138kV	EXTENSION	138.00	138.00	1	4.10	0.00	2	1272 ACSR
423	TL81-613 PERNELL OGE	PRAIRIE POINT	138.00	138.00	1	5.20	0.00	1	1533 ACSR
424	TL81-621 GRADY	CHOCTAW	138.00	138.00	1	4.10	0.15	1	1533 ACSR
425	TL81-675 TEXAS COMANCHE	PUMP 138KV TAP	69.00	138.00	1	5.56	0.00	1	1272 ACSR
426	SubTotal 138 kV Lines (Chan		0.00	0.00		92.20	2.35	0	
427	Total 138 kV Lines (All)		0.00	0.00		1,604.25	131.40	0	
428	TL81-824 MARKHAM FERRY SUB	PRYOR SUB W/TAP LONE STAR	115.00	138.00	1	2.15	0.00	0	795.0 ACSR
429	TL81-824 MARKHAM FERRY SUB	PRYOR SUB W/TAP LONE STAR	115.00	138.00	2	7.68	0.00	1	556.5 ACSR
430	TL81-824 MARKHAM FERRY SUB	PRYOR SUB W/TAP LONE STAR	115.00	138.00	3	0.48	0.00	1	556.5 ACSR
431	TL81-824A(RADIAL) LONE STAR TAP		115.00	138.00	2	0.16	0.00	1	556.5 ACSR

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
432	Total 115 kV Lines (All)		0.00	0.00		10.47	0.00	0	
433	TL66-103 WELEETKA PLANT	OG&E INTERCONNECT (SEMINOL)	69.00	69.00	3	0.11	0.00	0	266.8 ACSR
434	TL66-106 CHOUTEAU	TULSA SOUTHEAST	69.00	69.00	2	3.15	0.00	0	266.8 ACSR
435	TL66-106 CHOUTEAU	TULSA SOUTHEAST	0.00	0.00	0	0.00	0.00	0	2/0 CU Hard Drawn
436	TL66-106 CHOUTEAU	TULSA SOUTHEAST	0.00	0.00	0	0.00	0.00	0	4/0 ACSR
437	TL66-106 CHOUTEAU	TULSA SOUTHEAST	0.00	0.00	0	0.00	0.00	0	477.0 ACSR
438	TL66-106 CHOUTEAU	TULSA SOUTHEAST	0.00	0.00	0	0.00	0.00	0	556.5 ACSR
439	TL66-109 CATOOSA	DAWSON	69.00	69.00	1	5.99	0.00	0	477.0 ACSR
440	TL66-109 CATOOSA	DAWSON	69.00	69.00	2	1.07	0.00	1	477.0 ACSR
441	TL66-109 CATOOSA	DAWSON	69.00	69.00	1	0.23	0.00	1	556.5 ACSR
442	TL66-111 LONE OAK - RED OAK	WILBURTON	69.00	69.00	1	7.50	0.00	1	477 ACSR
443	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	1	0.51	0.00	1	556.5 ACSR
444	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	1	2.44	0.00	1	266.8 ACSR
445	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	1	0.60	0.00	1	795 ACSR
446	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	2	0.37	0.00	1	477 ACSR
447	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	3	0.79	0.00	2	636.0 ACSR
448	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	1	0.22	0.00	1	636.0 ACSR
449	TL66-112 SAND SPRINGS	SUNRAY DX	69.00	69.00	1	0.00	0.26	2	1272 ACSR
450	TL66-113 BARTLESVILLE COMAN	BLAKE STATION	69.00	69.00	2	12.00	4.71	0	4/0 ACSR
451	TL66-118 RED OAK SUB - MCCURTAIN	TALHINA	69.00	69.00	1	14.50	0.00	1	4/0 ACSR
452	TL66-118 RED OAK SUB - MCCURTAIN	TALHINA	69.00	138.00	1	0.02	0.00	1	795 ACSR
453	TL66-119 HUGO	VALLIANT 345 KV	69.00	69.00	2	5.37	0.00	2	477.0 ACSR and 795 ACSR
454	TL66-119 HUGO	VALLIANT 345 KV	69.00	69.00	2	2.33	0.00	1	477.0 ACSR
455	TL66-119 HUGO	VALLIANT 345 KV	69.00	69.00	1	1.06	0.00	1	477.0 ACSR
456	TL66-119 HUGO	VALLIANT 345 KV	69.00	69.00	2	1.51	0.00	2	477.0 ACSR
457	TL66-121 RED OAK (PSO)	HOWE (OG&E)	69.00	69.00	2	0.16	0.00	0	4/0 ACSR
458	TL66-130 ATOKA - HUGO	ANTLERS	69.00	69.00	2	1.50	0.00	1	4/0 ACSR
459	TL66-138 WELEETKA STATION	OKEMAH	69.00	69.00	2	11.83	0.11	0	4/0 ACSR
460	TL66-138 WELEETKA STATION	OKEMAH	0.00	0.00	3	0.11	0.00	0	4/0 CU
461	TL66-140 PRYOR JCT	PRYOR CITY(GRDA)	69.00	69.00	1	4.65	0.00	0	397.0 ACSR
462	TL66-141 CHOUTEAU	PRYOR CITY(GRDA)	69.00	69.00	1	1.89	0.00	0	2/0 ACSR
463	TL66-141 CHOUTEAU	PRYOR CITY(GRDA)	0.00	0.00	2	11.39	0.00	0	4/0 ACSR
464	TL66-141 CHOUTEAU	PRYOR CITY(GRDA)	0.00	0.00	2	0.16	0.00	0	477 ACSR
465	TL66-142 PRYOR JCT	VINITA	69.00	69.00	1	0.12	1.08	1	397.0 ACSR

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
466	TL66-145 VALLIANT 345	GEORGIA PACIFIC	69.00	69.00	1	12.19	1.50	0	4/0 ACSR
467	TL66-145 VALLIANT 345	GEORGIA PACIFIC	0.00	0.00	2	5.97	0.00	0	477.0 ACSR
468	TL66-146 GRDA TAP (AFTON)	EXPLORER PIPELINE PUMP	69.00	69.00	1	4.32	0.00	0	4/0 ACSR
469	TL66-147 GRDA TAP (RAMONA)	RAMONA	69.00	69.00	2	0.11	0.00	0	4/0 ACSR
470	TL66-148 GRDA TAP (AFTON)	AFTON	69.00	69.00	1	0.61	0.00	0	4/0 ACSR
471	TL66-149 VINITA	VINITA JUNCTION	69.00	69.00	1	0.04	2.81	0	397.0 ACSR
472	TL66-149 VINITA	VINITA JUNCTION	0.00	0.00	0	0.00	0.00	0	477.0 ACSR
473	TL66-150 DAWSON	COLLINSVILLE (GRDA)	69.00	69.00	1	6.44	0.00	1	4/0 ACSR
474	TL66-150 DAWSON	COLLINSVILLE (GRDA)	69.00	69.00	1	0.05	0.00	1	795 ACSR
475	TL66-601 FREDERICK JCT	SNYDER	69.00	69.00	1	0.06	0.00	0	1/0 ACSR
476	TL66-601 FREDERICK JCT	SNYDER	0.00	0.00	0	0.00	0.00	0	4/0 ACSR
477	TL66-606 HOBART CITY	SNYDER	69.00	69.00	1	5.38	0.00	0	3/0 ACSR
478	TL66-606 HOBART CITY	SNYDER	0.00	0.00	2	23.91	0.00	0	397.0 ACSR
479	TL66-606A ROOSEVELT AMOCO TAP		69.00	69.00	1	0.66	0.00	0	3/0 ACSR
480	TL66-607 FORT SILL	LAWTON EASTSIDE	69.00	69.00	1	4.32	5.74	1	477.0 ACSR
481	TL66-609 CORNVILLE	LINDSAY WATER FLOOD	69.00	69.00	1	0.76	0.29	0	# 2A CW
482	TL66-610 DUNCAN	COMANCHE(WFEC)	69.00	69.00	1	10.94	0.00	0	4/0 ACSR
483	TL66-611 HOBART CITY	HOBART JCT.	69.00	69.00	2	1.93	0.00	0	397.5 ACSR
484	TL66-612 SOUTHWESTERN	BINGER	69.00	69.00	2	15.19	0.00	0	266.8 ACSR
485	TL81-624A McGee Creek 138kV Extension		138.00	138.00	1	3.83	0.00	1	1272 ACSR
486	TL81-624B Antlers 138kV Extension		138.00	138.00	1	0.65	0.00	1	795 ACSR
487	TL81-624C Valley Timbers 138kV Extension		138.00	138.00	1	0.34	0.00	1	1272 ACSR
488	TL81-637A Headrick Tap	TIPTON	69.00	138.00	1	7.00	0.00	1	477.0 ACSR
489	STATION		0.00	0.00		0.00	0.00	0	397.0 ACSR
490	STATION		0.00	0.00		0.00	0.00	0	4/0 ACSR
491	TL66-617 FORT SILL	PORTER HILL	69.00	69.00	1	10.08	0.00	0	477.0 ACSR
492	TL66-618 ELGIN JCT	PORTER HILL	69.00	69.00	1	6.70	0.00	0	477.0 ACSR
493	TL66-619 LAWTON EASTSIDE	LAWTON WOLF CREEK	69.00	69.00	1	5.18	0.00	0	477.0 ACSR
494	TL66-619 LAWTON EASTSIDE	LAWTON WOLF CREEK	0.00	0.00	2	3.50	0.00	0	
495	TL66-619 LAWTON EASTSIDE	LAWTON WOLF CREEK	0.00	0.00	3	0.19	0.00	0	
496	TL66-622 WEATHERFORD	CLINTON	69.00	69.00	1	0.23	0.00	1	477.0 ACSR
497	TL66-624A Davidson Tap		69.00	69.00	1	4.10	0.00	1	477 ACSR

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
498	TL66-624 FREDERICK JCT	WTU Interconnect	69.00	69.00	3	0.62	0.00	1	4/0 ACSR
499	TL66-625 CYRIL	ELGIN JCT.	69.00	69.00	2	9.01	0.00	0	477.0 ACSR
500	TL66-626 CLINTON CITY	CLINTON JCT	69.00	69.00	1	5.40	0.00	1	477.0 ACSR
501	TL66-626 CLINTON CITY	CLINTON JCT	69.00	69.00	1	0.16	0.00	1	556.5 ACSR
502	TL66-626 CLINTON CITY	CLINTON JCT	69.00	69.00	1	0.08	0.00	1	477.0 ACSR
503	TL66-626A Foss Water Treatment Plant Tap		69.00	69.00	1	12.70	0.00	1	4/0 ACSR
504	TL66-627 DUKE	RUSSELL (WFEC)	69.00	69.00	1	2.50	0.00	0	4/0 ACSR
505	TL66-628 COMANCHE STATION	LAWTON EASTSIDE	69.00	69.00	1	0.45	4.92	0	477.0 ACSR
506	TL66-628 COMANCHE STATION	LAWTON EASTSIDE	0.00	0.00	0	0.00	0.00	0	795.0 ACSR
507	TL66-629 COMANCHE POWER STA	WALTERS JCT	69.00	69.00	1	13.02	0.00	0	477 ACSR
508	TL66-629 COMANCHE POWER STA	WALTERS JCT	0.00	0.00	1	4.84	0.00	0	4/0 ACSR
509	TL66-629 COMANCHE POWER STA	WALTERS JCT	0.00	0.00	1	1.46	0.00	0	397 ACSR
510	TL66-630 WAURIKA	COMANCHE (WFEC)	69.00	69.00	1	20.07	0.70	0	266.8 ACSR
511	TL66-630 WAURIKA	COMANCHE (WFEC)	0.00	0.00		0.00	0.00	0	397.0 ACSR
512	TL66-630 WAURIKA	COMANCHE (WFEC)	0.00	0.00		0.00	0.00	0	4/0 ACSR
513	TL66-630 WAURIKA	COMANCHE (WFEC)	0.00	0.00		0.00	0.00	0	477.0 ACSR
514	TL66-631 ELK CITY	HAMMON JCT	69.00	69.00	1	17.25	0.00	1	4/0 ACSR
515	TL66-631 ELK CITY	HAMMON JCT	0.00	0.00	2	0.88	0.00	1	477.0 ACSR
516	TL66-631 ELK CITY	HAMMON JCT	69.00	69.00	1	0.14	0.00	1	556.5 ACSR
517	TL66-632 WEATHERFORD	WEATHERFORD SE	69.00	69.00	1	2.20	0.00	0	477.0 ACSR
518	SubTotal 69 kV Lines		0.00	0.00		365.35	35.95	0	
519	Line cost and expense are transmission lines	not available by individual Total shown in Column j-p							
36	TOTAL					7,282.77	351.82	606	

Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
518							
519	49,685,932	615,312,937	664,998,869	82,526	4,162,482		4,245,008
36	49,685,932.00	615,312,937.00	664,998,869.00	82,526.00	4,162,482.00	0.00	4,245,008.00

Name of Respondent: Public Service Company of Oklahoma	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	[(a)] TL81-634 RIVERSIDE	RS PEAKER	0.20	1	1	1	1	795	ACSR		138
44	TOTAL		0		1	1	1				

Line No.	LINE COST					Construction
	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	(q)
1		864,369	90,740		955,109	
44		864,369	90,740		955,109	

Name of Respondent: Public Service Company of Oklahoma	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: TransmissionLineStartPoint
Radial line investment was transferred from AEP Oklahoma Transmission Company, Inc. to Public Service Company of Oklahoma per FERC Docket No. EC20-91-000.

Name of Respondent: Public Service Company of Oklahoma	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: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
1	116TH & PEORIA - OK	Transmission		138.00	13.80	0.00	12.00	1	0
2	116TH & PEORIA - OK	Transmission		138.00	13.09	0.00	15.00	1	0
3	136TH & YALE - OK	Distribution		138.00	13.09	0.00	14.00	1	0
4	141ST & PINE - OK	Transmission		138.00	13.80	0.00	25.00	1	0
5	141ST & PINE - OK	Transmission		13.80	0.00	0.00	0.00	0	0
6	15TH & FULTON - OK	Transmission		138.00	13.80	0.00	80.00	2	0
7	15TH & PEORIA - OK	Transmission		13.20	4.16	0.00	3.00	1	0
8	15TH & PEORIA - OK	Transmission		13.20	4.36	0.00	4.68	1	0
9	1ST & PEORIA - OK	Transmission		13.20	4.36	0.00	9.36	2	0
10	36TH & LEWIS - OK	Transmission		138.00	13.80	0.00	74.60	2	0
11	36TH & LEWIS - OK	Transmission		13.20	4.16	0.00	5.00	1	0
12	36TH & OLYMPIA - OK	Transmission		138.00	13.80	0.00	80.00	2	0
13	36TH AND PITTSBURG - OK	Distribution		13.20	4.36	0.00	16.86	4	0
14	46TH STREET NORTH - OK	Distribution		138.00	13.80	0.00	37.30	1	0
15	48TH AND VANCOUVER - OK	Distribution		13.20	4.36	0.00	5.60	1	0
16	52ND AND DELAWARE - OK	Distribution		138.00	13.80	0.00	74.60	2	0
17	53RD & GARNETT - OK	Transmission		138.00	13.80	0.00	74.60	2	0
18	5TH STREET - OK	Distribution		13.80	2.40	0.00	6.25	1	0
19	72ND AND ELWOOD - OK	Distribution		13.80	0.00	0.00	0.00	0	0
20	72ND AND ELWOOD - OK	Distribution		138.00	13.80	0.00	25.00	1	0
21	77TH & MEMORIAL - OK	Distribution		138.00	13.80	0.00	74.60	2	0
22	77TH & MEMORIAL - OK	Distribution		13.80	0.00	0.00	0.00	0	0
23	81ST & GARNETT - OK	Distribution		138.00	13.80	0.00	40.00	1	0
24	81ST & GARNETT - OK	Distribution		138.00	0.00	0.00	0.00	0	0
25	81ST & GARNETT - OK	Distribution		138.00	13.80	0.00	74.60	2	0
26	81ST AND YALE - OK	Distribution		138.00	13.20	0.00	74.60	2	0
27	96TH & YALE - OK	Transmission		138.00	13.80	0.00	37.30	1	0
28	ADAIR - OK	Transmission		69.00	13.80	0.00	10.50	1	0
29	AFTON - OK	Transmission		69.00	13.20	0.00	9.36	3	0
30	AFTON CONTL PIPE(CHEROKE - OK	Transmission		2.40	0.00	0.00	0.00	0	0
31	AFTON CONTL PIPE(CHEROKE - OK	Transmission		69.00	2.40	0.00	3.75	3	0
32	AFTON EXPLORER PUMP - OK	Transmission		69.00	2.40	0.00	9.39	3	0
33	AGRICO-TERRA NITROGEN - OK	Distribution		138.00	4.36	0.00	28.00	2	0
34	AGRICO-TERRA NITROGEN - OK	Transmission		138.00	4.36	2.52	25.00	1	0
35	ALEX BRADLEY - OK	Distribution		138.00	13.80	0.00	9.38	1	0
36	ALLEN 138KV - OK	Transmission		138.00	13.80	0.00	20.00	1	0
37	ALLEN TRANSOK - OK	Transmission		138.00	4.16	0.00	22.40	1	0
38	ALLUWE SHELL - OK	Transmission		138.00	4.30	0.00	7.00	1	0
39	ALTUS JUNCTION - OK	Transmission		69.00	34.50	0.00	14.00	1	0
40	ALTUS JUNCTION - OK	Transmission		138.00	69.00	13.80	93.30	1	0
41	ALTUS JUNCTION - OK	Transmission		34.50	13.80	0.00	5.00	1	0
42	ALTUS JUNCTION - OK	Transmission		69.00	0.00	0.00	0.00	0	0
43	AMERICAN AIRLINE CO. - OK	Transmission		13.80	0.00	0.00	0.00	0	0
44	AMERICAN AIRLINE CO. - OK	Distribution		138.00	13.80	0.00	74.60	2	0
45	ANTLERS - OK	Distribution		69.00	13.80	0.00	14.00	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
46	ATOKA 138 - OK	Distribution		69.00	0.00	0.00	0.00	0	0
47	ATOKA 138 - OK	Transmission		69.00	0.00	0.00	0.00	0	0
48	ATOKA 138 - OK	Distribution		138.00	70.50	13.09	54.00	1	0
49	ATOKA 138 - OK	Distribution		138.00	23.90	0.00	22.40	0	1
50	ATOKA PUMP - OK	Distribution		69.00	4.16	0.00	9.38	1	0
51	BARNSDALL TAP - OK	Distribution		138.00	34.50	13.80	33.60	1	0
52	BARNSDALL TAP - OK	Distribution		138.00	13.80	0.00	22.40	1	0
53	BARNSDALL TAP - OK	Distribution		34.50	0.00	0.00	0.00	0	0
54	BARTLESVILLE COMANCHE - OK	Distribution		138.00	70.50	36.20	30.00	1	0
55	BARTLESVILLE COMANCHE - OK	Transmission		13.80	0.00	0.00	0.00	0	0
56	BARTLESVILLE COMANCHE - OK	Distribution		138.00	69.00	36.20	30.00	0	1
57	BARTLESVILLE COMANCHE - OK	Distribution		138.00	13.80	0.00	37.30	1	0
58	BARTLESVILLE COMANCHE - OK	Distribution		138.00	13.20	0.00	37.30	1	0
59	BARTLESVILLE SOUTHEAST - OK	Distribution		138.00	13.80	0.00	74.60	2	0
60	BARTLESVILLE SOUTHEAST - OK	Distribution		13.80	0.00	0.00	0.00	0	0
61	BELLAIRE - OK	Distribution		13.20	4.36	0.00	9.36	2	0
62	BENTON OIL - OK	Distribution		34.50	13.80	0.00	4.20	1	0
63	BINGER 69 - OK	Distribution		69.00	13.80	0.00	6.00	1	0
64	BIRD CREEK PUMP - OK	Distribution		138.00	0.00	0.00	0.00	0	0
65	BIRD CREEK PUMP - OK	Distribution		138.00	4.16	0.00	5.60	1	0
66	BIRD HOLLOW - OK	Distribution		138.00	13.80	0.00	20.00	1	0
67	BIXBY 111TH STREET - OK	Distribution		138.00	13.09	0.00	20.00	1	0
68	BIXBY 111TH STREET - OK	Distribution		138.00	13.80	0.00	74.60	2	0
69	BIXBY 111TH STREET - OK	Distribution		138.00	0.00	0.00	0.00	0	0
70	BLAKE - OK	Distribution		13.80	2.40	0.00	2.00	1	0
71	BLAKE - OK	Distribution		69.00	2.40	0.00	9.39	3	0
72	BLANCHARD SOUTH - OK	Distribution		138.00	13.80	0.00	20.00	1	0
73	BLOOMFIELD - OK	Distribution		13.20	4.36	0.00	9.36	2	0
74	BLUESTEM - OK	Distribution		138.00	13.80	0.00	22.40	1	0
75	BROKEN ARROW 101ST SOUTH - OK	Distribution		138.00	13.80	0.00	77.30	2	0
76	BROKEN ARROW 71ST - OK	Distribution		138.00	13.80	0.00	40.00	1	0
77	BROKEN ARROW 81ST - OK	Distribution		13.80	0.00	0.00	0.00	0	0
78	BROKEN ARROW 81ST - OK	Transmission		138.00	13.80	0.00	74.60	2	0
79	BROKEN ARROW NORTH - OK	Distribution		138.00	13.80	0.00	74.60	2	0
80	BROKEN ARROW WATER PLANT - OK	Distribution		69.00	13.80	0.00	9.38	1	0
81	BROKEN BOW - OK	Transmission		138.00	13.80	0.00	26.50	2	0
82	BROOKSIDE (PO) - OK	Transmission		13.20	4.33	0.00	22.50	3	0
83	BUTLER (PO) - OK	Transmission		34.50	4.40	0.00	1.68	1	0
84	CACHE - OK	Transmission		138.00	13.80	0.00	7.84	1	0
85	CANADIAN COUNTY NATURAL GAS - OK	Transmission		138.00	4.10	0.00	10.50	1	0
86	CANUTE - OK	Transmission		34.50	13.80	0.00	5.60	1	0
87	CARNES - OK	Distribution		34.50	13.80	0.00	5.25	1	0
88	CARSON - OK	Transmission		138.00	14.15	0.00	89.60	4	0
89	CARTER - OK	Transmission		34.50	4.16	0.00	3.00	3	0
90	CATOOSA - OK	Transmission		138.00	0.00	0.00	0.00	0	0

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)			
91	CATOOSA - OK	Transmission		138.00	69.00	13.80	54.00	1	0
92	CATOOSA - OK	Transmission		138.00	13.20	0.00	10.50	1	0
93	CATOOSA - OK	Distribution		138.00	13.80	0.00	37.30	1	0
94	CHELSEA - OK	Transmission		138.00	13.80	0.00	10.50	1	0
95	CHEROKEE INDUSTRIAL PARK - OK	Transmission		138.00	13.80	0.00	33.60	2	0
96	CHEYENNE - OK	Transmission		34.50	4.36	0.00	5.25	1	0
97	CHICKASHA NORTH 29TH - OK	Distribution		138.00	13.80	0.00	37.30	1	0
98	CHOUTEAU - OK	Distribution		69.00	13.20	0.00	10.50	1	0
99	CHOUTEAU - OK	Distribution		138.00	13.80	0.00	14.00	1	0
100	CLAYTON - OK	Distribution		138.00	13.80	0.00	5.60	1	0
101	CLINTON CITY - OK	Transmission		69.00	34.50	14.40	12.50	1	0
102	CLINTON CITY - OK	Transmission		13.80	0.00	0.00	0.00	0	0
103	CLINTON CITY - OK	Distribution		69.00	13.80	0.00	44.80	2	0
104	CLINTON JUNCTION - OK	Distribution		138.00	13.80	0.00	37.30	1	0
105	CLINTON JUNCTION - OK	Distribution		13.80	0.00	0.00	0.00	0	0
106	CLINTON JUNCTION - OK	Distribution		138.00	69.00	13.80	84.00	1	0
107	CLINTON NAT. GAS - OK	Distribution		138.00	4.36	0.00	36.40	2	0
108	CLINTON SHERMAN I A P - OK	Distribution		138.00	13.80	0.00	8.40	1	0
109	COALGATE PUMP - OK	Distribution		138.00	4.36	0.00	4.20	1	0
110	COLLEGE - OK	Distribution		13.20	4.36	0.00	4.68	1	0
111	COMANCHE TEXAS PUMP - OK	Distribution		69.00	2.40	0.00	6.90	3	0
112	COPAN SOUTH - OK	Distribution		69.00	13.20	0.00	5.01	3	0
113	CORN COLONY - OK	Distribution		34.50	13.80	0.00	4.68	1	0
114	CORNVILLE - OK	Distribution		138.00	13.80	0.00	37.30	1	0
115	CORNVILLE - OK	Distribution		138.00	70.50	34.50	50.00	1	0
116	COWETA JUNCTION - OK	Distribution		69.00	13.80	0.00	10.00	1	0
117	CRAIG JUNCTION - OK	Distribution		138.00	13.80	0.00	4.20	1	0
118	CROWDER STEP DOWN - OK	Distribution		26.00	13.80	0.00	3.75	3	0
119	CYRIL - OK	Distribution		69.00	13.80	0.00	8.40	1	0
120	CYRIL - OK	Distribution		69.00	4.16	0.00	5.84	3	0
121	DARBY - OK	Distribution		34.50	13.20	0.00	3.12	3	0
122	DARLINGTON ROAD - OK	Distribution		138.00	13.80	0.00	50.00	2	0
123	DAVIDSON (PO) - OK	Distribution		69.00	13.09	4.16	6.25	1	0
124	DAWSON - OK	Distribution		138.00	13.80	0.00	33.30	1	0
125	DAWSON - OK	Distribution		69.00	13.20	0.00	66.00	2	0
126	DAWSON - OK	Distribution		138.00	70.50	13.09	54.00	1	0
127	DELAWARE 345 - OK	Distribution		345.00	137.50	13.80	450.00	1	0
128	DENVER SUB - OK	Distribution		138.00	14.15	0.00	111.90	3	0
129	DUKE - OK	Distribution		69.00	34.50	0.00	14.00	1	0
130	DUNCAN 138 - OK	Distribution		138.00	69.00	13.80	90.00	1	0
131	DUNCAN 138 - OK	Distribution		13.80	0.00	0.00	0.00	0	0
132	DUNCAN 138 - OK	Distribution		69.00	13.09	0.00	25.00	1	0
133	DUNCAN 6TH STREET - OK	Transmission		13.80	2.40	0.00	4.20	1	0
134	DUNCAN EASTSIDE - OK	Transmission		138.00	13.80	0.00	37.30	1	0
135	DUNCAN SUNRAY (TOSCO) - OK	Transmission		69.00	13.80	2.40	12.50	1	0
136	DUSTIN - OK	Transmission		138.00	13.80	0.00	7.00	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
137	EARLSBORO - OK	Distribution		138.00	4.36	0.00	40.00	2	0
138	EAST 121ST STREET - OK	Distribution		138.00	13.80	0.00	40.00	1	0
139	EAST 121ST STREET - OK	Distribution		13.80	0.00	0.00	0.00	0	0
140	EAST 21ST STREET - OK	Distribution		138.00	13.80	0.00	74.60	2	0
141	EAST 61ST STREET - OK	Transmission		138.00	13.80	0.00	74.60	2	0
142	ELGIN JUNCTION - OK	Transmission		138.00	69.00	13.80	50.40	1	0
143	ELK CITY - OK	Distribution		138.00	69.00	13.80	56.00	1	0
144	ELK CITY - OK	Transmission		69.00	34.50	14.40	27.56	1	0
145	ELK CITY - OK	Transmission		138.00	13.80	0.00	22.40	1	0
146	ELK CITY - OK	Transmission		230.00	141.45	13.80	450.00	1	0
147	ELK CITY FALCON ROAD - OK	Transmission		138.00	13.80	0.00	37.30	1	0
148	ELLIS 4KV SUB - OK	Transmission		138.00	4.36	0.00	50.00	2	0
149	ERICK - OK	Transmission		34.50	13.80	0.00	9.38	1	0
150	FLETCHER-TEMPLE EASTEX - OK	Distribution		138.00	13.80	0.00	7.00	1	0
151	FORD GLASS - OK	Distribution		138.00	13.80	0.00	44.80	2	0
152	FORT SILL - OK	Distribution		69.00	13.80	0.00	53.00	2	0
153	FORT SILL - OK	Distribution		13.80	0.00	0.00	0.00	0	0
154	FORT SILL MOW-WAY - OK	Distribution		138.00	13.80	0.00	48.00	2	0
155	FORT TOWSON - OK	Transmission		69.00	13.20	0.00	5.00	3	0
156	FOSS CITY - OK	Distribution		34.50	13.20	0.00	1.68	1	0
157	FOSS WATER TREATMENT PLAN - OK	Transmission		69.00	13.80	0.00	3.50	1	0
158	FREDERICK JUNCTION - OK	Transmission		69.00	13.20	2.40	1.50	3	0
159	GLENHAVEN - OK	Distribution		13.20	4.36	0.00	9.36	2	0
160	GOULD - OK	Transmission		34.50	4.16	0.00	1.50	1	0
161	GRADY COUNTY POD - OK	Distribution		138.00	0.00	0.00	0.00	0	0
162	GRADY COUNTY POD - OK	Distribution		138.00	0.00	0.00	0.00	0	0
163	GRADY COUNTY POD - OK	Distribution		138.00	4.36	0.00	75.00	3	0
164	GRANDFIELD - OK	Distribution		34.50	13.20	0.00	3.75	1	0
165	GRANITE - OK	Distribution		34.50	13.80	0.00	4.20	1	0
166	GROVE - OK	Distribution		161.00	138.00	13.80	112.00	1	0
167	GROVE - OK	Transmission		138.00	13.80	0.00	44.80	2	0
168	HALLIBURTON NO. 2 - OK	Transmission		13.20	2.40	0.00	4.68	3	0
169	HAMMON JUNCTION - OK	Transmission		34.50	13.20	0.00	2.50	1	0
170	HAMMON JUNCTION - OK	Transmission		34.50	13.80	0.00	2.50	0	1
171	HAMMON JUNCTION - OK	Distribution		34.50	13.80	0.00	2.50	0	1
172	HAMMON JUNCTION - OK	Distribution		34.50	13.80	0.00	2.50	0	1
173	HAMMON JUNCTION - OK	Transmission		34.50	13.80	0.00	2.50	0	1
174	HAMMON JUNCTION - OK	Transmission		34.50	13.80	0.00	2.50	0	1
175	HAMMON JUNCTION - OK	Transmission		34.50	13.80	0.00	2.50	0	1
176	HAMMON JUNCTION - OK	Transmission		34.50	13.80	0.00	2.50	0	1
177	HAMMON JUNCTION - OK	Transmission		34.50	13.80	0.00	2.50	0	1
178	HAMMON JUNCTION - OK	Distribution		69.00	34.50	0.00	25.00	1	0
179	HASKELL AND ZUNIS - OK	Distribution		13.20	4.36	0.00	9.36	2	0
180	HAWTHORNE PUMP - OK	Distribution		138.00	4.16	0.00	10.50	1	0
181	HEADRICK - OK	Distribution		69.00	12.40	0.00	3.00	3	0
182	HENRYETTA - OK	Distribution		138.00	13.80	0.00	74.60	2	0

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		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
183	HIGHWAY 20 - OK	Distribution		138.00	34.50	13.80	8.40	1	0
184	HOBART CITY - OK	Distribution		13.80	0.00	0.00	0.00	0	0
185	HOBART CITY - OK	Distribution		69.00	13.80	0.00	19.88	2	0
186	HOBART CITY - OK	Distribution		69.00	34.50	14.40	27.56	1	0
187	HOBART JUNCTION - OK	Distribution		138.00	66.00	13.80	75.00	1	0
188	HOBART JUNCTION - OK	Distribution		13.80	0.00	0.00	0.00	0	0
189	HOLDENVILLE EXPLORER - OK	Distribution		138.00	4.16	0.00	22.40	1	0
190	HOLLIS - OK	Transmission		34.50	4.16	0.00	9.38	1	0
191	HOLLIS - OK	Transmission		34.50	4.16	0.00	5.25	0	1
192	HOLLIS - OK	Transmission		138.00	34.50	0.00	14.00	1	0
193	HOMINY PRISON - OK	Transmission		34.50	13.20	0.00	7.00	1	0
194	HUGO - OK	Transmission		138.00	13.80	0.00	22.40	1	0
195	HUGO - OK	Transmission		138.00	70.50	13.09	90.00	1	0
196	HUGO - OK	Distribution		69.00	13.80	0.00	21.00	2	0
197	IDABEL - OK	Distribution		138.00	13.80	0.00	37.40	2	0
198	IDABEL-GEORGIA PACIFIC - OK	Distribution		69.00	13.80	0.00	10.50	1	0
199	INOLA (TS4) - OK	Distribution		138.00	13.80	0.00	22.40	1	0
200	JAMESTOWN - OK	Distribution		13.20	4.36	0.00	14.04	3	0
201	JAY (PO) - OK	Distribution		138.00	13.80	0.00	14.00	1	0
202	JENKS - OK	Distribution		138.00	13.80	0.00	20.00	1	0
203	KENOSHA - OK	Transmission		138.00	13.80	0.00	74.60	2	0
204	KIAMICHI PUMPING - OK	Transmission		69.00	2.40	0.00	4.00	6	0
205	LAWTON 112TH AND W GORE - OK	Transmission		138.00	13.80	0.00	22.40	1	0
206	LAWTON 53RD & CACHE ROAD - OK	Distribution		138.00	13.80	0.00	37.33	1	0
207	LAWTON AIR GAS - OK	Distribution		138.00	4.10	0.00	37.30	1	0
208	LAWTON DISP PLANT - OK	Distribution		69.00	13.80	0.00	7.00	1	0
209	LAWTON EASTSIDE - OK	Transmission		138.00	69.00	13.80	129.00	2	0
210	LAWTON EASTSIDE - OK	Distribution		138.00	13.80	0.00	37.30	1	0
211	LAWTON EASTSIDE - OK	Distribution		345.00	137.50	13.80	270.00	1	0
212	LAWTON EASTSIDE - OK	Distribution		13.80	0.00	0.00	0.00	0	0
213	LAWTON EASTSIDE - OK	Transmission		345.00	138.00	13.80	270.00	1	0
214	LAWTON GOODYEAR - OK	Distribution		138.00	4.36	0.00	11.20	1	0
215	LAWTON GOODYEAR - OK	Distribution		138.00	4.36	0.00	70.00	5	0
216	LAWTON GORE - OK	Transmission		69.00	13.20	0.00	37.30	1	0
217	LAWTON PAPERBOARD - OK	Transmission		13.80	0.00	0.00	0.00	0	0
218	LAWTON PAPERBOARD - OK	Distribution		138.00	13.80	0.00	37.30	1	0
219	LAWTON SHERIDAN ROAD - OK	Distribution		138.00	13.80	0.00	74.60	2	0
220	LAWTON WEST SIDE - OK	Distribution		13.80	0.00	0.00	0.00	0	0
221	LAWTON WEST SIDE - OK	Distribution		138.00	13.80	0.00	74.60	2	0
222	LAWTON WOLF CREEK - OK	Distribution		69.00	13.80	0.00	37.30	1	0
223	LEHIGH CITY - OK	Distribution		138.00	23.90	0.00	30.50	2	0
224	LEQUIRE - OK	Distribution		138.00	13.80	0.00	10.50	1	0
225	LINDSAY TEXAS PIPELINE CO - OK	Distribution		138.00	4.16	0.00	12.50	1	0
226	LINDSAY WATER FLOOD - OK	Distribution		138.00	13.80	0.00	25.00	1	0
227	LOCUST GROVE - OK	Transmission		115.00	13.09	0.00	15.00	1	0
228	LONE OAK - OK	Distribution		138.00	23.00	0.00	40.00	2	0

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		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
229	LONE OAK - OK	Transmission		138.00	70.50	13.80	108.00	2	0
230	LONE OAK - OK	Transmission		138.00	23.90	0.00	40.00	2	0
231	LONE OAK - OK	Transmission		13.80	0.00	0.00	0.00	0	0
232	LONE WOLF - OK	Transmission		34.50	13.80	0.00	5.25	1	0
233	LYNN LANE - OK	Transmission		138.00	13.80	0.00	20.00	1	0
234	LYNN LANE - OK	Distribution		138.00	13.80	0.00	22.40	1	0
235	LYNN LANE & 121ST - OK	Distribution		138.00	13.09	0.00	40.00	1	0
236	MAPLEWOOD - OK	Distribution		13.20	4.36	0.00	4.68	1	0
237	MAPLEWOOD - OK	Distribution		13.20	4.10	0.00	7.20	2	0
238	MARTHA SUB - OK	Distribution		138.00	13.80	0.00	9.38	1	0
239	MARY FRANCIS - OK	Transmission		13.20	4.36	0.00	9.36	2	0
240	MAYO ROAD - OK	Transmission		138.00	13.80	0.00	22.40	1	0
241	MAYO ROAD - OK	Transmission		13.80	0.00	0.00	0.00	0	0
242	MCALESTER CHEROKEE - OK	Transmission		23.00	4.36	0.00	9.37	2	0
243	MCALESTER CITY - OK	Distribution		69.00	4.40	0.00	8.63	3	0
244	MCALESTER CITY - OK	Distribution		23.00	0.00	0.00	0.00	0	0
245	MCALESTER CITY - OK	Distribution		138.00	69.00	13.80	56.00	1	0
246	MCALESTER CITY - OK	Distribution		138.00	23.90	0.00	74.60	2	0
247	MCALESTER INDUSTRIAL - OK	Distribution		138.00	23.90	0.00	50.00	2	0
248	MCALESTER OIL WELL - OK	Distribution		26.00	2.40	0.00	4.00	3	0
249	MCALESTER SOUTH - OK	Distribution		138.00	23.90	0.00	37.30	1	0
250	MCGEE CREEK - OK	Distribution		69.00	4.36	0.00	7.00	1	0
251	MIDLAND (PS) - OK	Distribution		13.20	4.36	0.00	9.36	2	0
252	MINGO - OK	Distribution		13.80	0.00	0.00	0.00	0	0
253	MINGO - OK	Transmission		138.00	13.80	0.00	44.80	2	0
254	MOHAWK PUMP - OK	Distribution		138.00	13.80	7.97	38.40	2	0
255	MOUND ROAD - OK	Distribution		138.00	13.80	0.00	37.30	1	0
256	MOUND ROAD - OK	Distribution		138.00	13.20	0.00	37.30	1	0
257	MOUNTAIN VIEW - OK	Transmission		34.50	4.40	0.00	5.25	1	0
258	NORGE ROAD - OK	Transmission		138.00	13.80	0.00	44.80	2	0
259	NORGE ROAD - OK	Transmission		13.80	0.00	0.00	0.00	0	0
260	NORTH HARVARD - OK	Transmission		13.20	4.10	0.00	3.75	0	1
261	NORTH MINGO - OK	Transmission		138.00	13.80	0.00	40.00	1	0
262	NORTHEASTERN 138 - OK	Transmission		138.00	13.80	0.00	7.50	1	0
263	NORTHEASTERN 345 - OK	Transmission		345.00	138.00	34.50	675.00	0	1
264	NOWATA - OK	Distribution		138.00	13.80	0.00	22.40	1	0
265	OAKS - OK	Distribution		13.20	4.33	0.00	7.50	1	0
266	OAKS 138 - OK	Distribution		138.00	13.80	7.96	22.40	1	0
267	OAKS 138 - OK	Transmission		138.00	13.80	0.00	40.00	1	0
268	OKEMAH - OK	Transmission		69.00	13.09	0.00	20.00	1	0
269	OKMULGEE CITY - OK	Distribution		138.00	4.16	0.00	9.38	1	0
270	OKMULGEE CITY - OK	Distribution		138.00	13.80	0.00	37.30	1	0
271	OKMULGEE CITY - OK	Distribution		13.80	0.00	0.00	0.00	0	0
272	ONETA - OK	Distribution		345.00	141.45	13.80	560.00	1	0
273	ONETA - OK	Distribution		345.00	138.00	34.50	1350.00	2	0
274	ONETA - OK	Distribution		138.00	13.80	7.90	22.40	1	0
275	ONETA - OK	Distribution		138.00	13.80	79.00	22.40	1	0

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276	ORAL ROBERTS UNIVERSITY - OK	Distribution		13.80	0.00	0.00	0.00	0	0
277	ORAL ROBERTS UNIVERSITY - OK	Distribution		138.00	13.80	0.00	20.00	1	0
278	ORAL ROBERTS UNIVERSITY - OK	Transmission		13.80	0.00	0.00	0.00	0	0
279	OWASSO 109TH STREET - OK	Transmission		13.80	0.00	0.00	0.00	0	0
280	OWASSO 109TH STREET - OK	Distribution		138.00	13.80	0.00	27.00	2	0
281	OWASSO 86TH STREET - OK	Distribution		138.00	13.80	7.96	44.80	2	0
282	OWASSO 88TH & MINGO - OK	Distribution		138.00	13.80	0.00	40.00	1	0
283	PERNELL - OK	Distribution		138.00	4.36	2.52	15.00	1	0
284	PHILLIPS GAS CO. - OK	Distribution		138.00	13.80	0.00	9.38	1	0
285	PINE AND OSAGE - OK	Distribution		13.20	4.36	0.00	7.50	2	0
286	PINE AND PEORIA - OK	Distribution		138.00	13.80	7.96	44.80	2	0
287	PITTSBURG (PO) - OK	Distribution		69.00	13.20	0.00	4.50	3	0
288	PORT OF CATOOSA - OK	Distribution		138.00	13.80	0.00	37.30	1	0
289	PORT OF CATOOSA - OK	Distribution		13.80	0.00	0.00	0.00	0	0
290	PORT OF CATOOSA - OK	Transmission		138.00	13.80	0.00	24.00	1	0
291	PORTER HILL - OK	Transmission		69.00	13.09	0.00	8.40	1	0
292	PRATTVILLE - OK	Transmission		138.00	13.80	0.00	22.40	1	0
293	PRUE - OK	Transmission		34.50	13.20	0.00	1.68	1	0
294	PRYOR CEMENT - OK	Distribution		115.00	4.36	0.00	26.50	3	0
295	PRYOR CONTINENTAL PIPE - OK	Distribution		69.00	2.40	0.00	2.25	3	0
296	PRYOR CREEK - OK	Distribution		138.00	13.80	0.00	50.40	4	0
297	PRYOR CREEK - OK	Distribution		13.80	0.00	0.00	0.00	0	0
298	PRYOR JUNCTION - OK	Distribution		138.00	69.00	13.80	130.00	1	0
299	RAMONA - OK	Distribution		69.00	13.09	0.00	9.38	1	0
300	RED FORK - OK	Distribution		13.20	4.36	0.00	5.00	1	0
301	RED OAK (PO) - OK	Distribution		69.00	13.09	0.00	9.38	1	0
302	RED OAK PUMP - OK	Distribution		4.16	0.00	0.00	0.00	0	0
303	RED OAK PUMP - OK	Distribution		138.00	4.16	0.00	20.00	1	0
304	RIVERSIDE 345KV - OK	Distribution		345.00	138.00	34.50	1350.00	2	0
305	RIVERVIEW (PO) - OK	Distribution		13.20	4.36	0.00	3.75	1	0
306	ROOSEVELT AMOCO - OK	Distribution		69.00	4.36	0.00	6.25	1	0
307	ROOSEVELT AMOCO - OK	Distribution		69.00	12.47	0.00	2.00	2	0
308	ROOSEVELT AMOCO - OK	Distribution		69.00	14.00	0.00	0.50	1	0
309	RUSH SPRINGS CHESTNUT - OK	Distribution		138.00	13.80	0.00	7.00	1	0
310	RUSH SPRINGS NAT GAS - OK	Transmission		138.00	4.16	0.00	22.40	1	0
311	SAILBOAT BRIDGE - OK	Transmission		69.00	13.80	0.00	10.50	1	0
312	SAND SPRINGS 138KV - OK	Distribution		138.00	13.80	0.00	74.60	2	0
313	SAPULPA ROAD - OK	Distribution		345.00	141.45	13.80	560.00	1	0
314	SAVANNA - OK	Distribution		69.00	13.80	0.00	9.38	1	0
315	SAWYER HUGO WTR. PLANT - OK	Distribution		69.00	13.20	0.00	2.00	3	0
316	SAYRE - OK	Distribution		34.50	13.20	0.00	9.38	1	0
317	SAYRE - OK	Distribution		138.00	13.80	0.00	14.00	1	0
318	SAYRE - OK	Distribution		138.00	0.00	0.00	0.00	0	0
319	SENTINEL CITY - OK	Distribution		34.50	4.36	0.00	5.25	1	0
320	SHIDLER - OK	Transmission		138.00	13.80	7.90	22.40	1	0
321	SHIDLER - OK	Transmission		138.00	13.80	0.00	14.00	1	0
322	SKIATOOK WATER PUMP - OK	Transmission		138.00	2.50	0.00	7.00	1	0

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323	SKIATOOK WATER PUMP - OK	Transmission		138.00	0.00	0.00	0.00	0	0
324	SNYDER - OK	Distribution		138.00	66.00	13.20	75.00	1	0
325	SNYDER - OK	Distribution		69.00	13.80	0.00	3.75	3	0
326	SNYDER - OK	Distribution		69.00	4.16	0.00	4.20	1	0
327	SNYDER - OK	Distribution		13.80	0.00	0.00	0.00	0	0
328	SOUTH COFFEYVILLE - OK	Distribution		138.00	13.80	0.00	47.80	2	0
329	SOUTH HUDSON - OK	Distribution		138.00	13.80	0.00	40.00	2	0
330	SOUTHERN HILLS - OK	Distribution		138.00	13.80	0.00	93.30	2	0
331	SOUTHWESTERN STATION - OK	Distribution		69.00	13.80	0.00	5.25	1	0
332	SOUTHWESTERN STATION - OK	Distribution		138.00	69.00	13.80	0.00	1	0
333	STIGLER - OK	Distribution		138.00	13.80	0.00	25.63	2	0
334	STUART LINE - OK	Distribution		23.00	13.20	0.00	5.00	1	0
335	TALIHINA WEST - OK	Distribution		69.00	13.80	0.00	14.00	1	0
336	TEMPLE - OK	Distribution		34.50	4.10	0.00	3.75	3	0
337	TERRAL - OK	Distribution		34.50	13.80	0.00	4.20	1	0
338	THOMAS (PO) - OK	Distribution		69.00	13.80	0.00	5.20	1	0
339	THOMAS OK REFINING CO. - OK	Distribution		69.00	13.80	0.00	10.50	1	0
340	TIPTON CITY - OK	Distribution		69.00	4.40	0.00	4.20	1	0
341	TRANSOK CLAREMORE - OK	Distribution		4.16	0.00	0.00	0.00	0	0
342	TRANSOK CLAREMORE - OK	Transmission		138.00	4.16	0.00	22.40	1	0
343	TULSA APACHE - OK	Transmission		13.20	4.36	0.00	4.68	1	0
344	TULSA FAIRGROUNDS - OK	Transmission		13.20	4.16	0.00	5.00	1	0
345	TULSA FAIRGROUNDS - OK	Transmission		13.20	4.30	0.00	5.00	1	0
346	TULSA INT AIRPORT - OK	Distribution		13.20	4.36	0.00	7.50	2	0
347	TULSA NORTH 138 - OK	Distribution		13.80	0.00	0.00	0.00	0	0
348	TULSA NORTH 138 - OK	Transmission		138.00	13.80	0.00	22.40	1	0
349	TULSA NORTH 345 - OK	Distribution		345.00	141.45	13.80	560.00	0	1
350	TULSA POWER - OK	Distribution		69.00	13.09	0.00	15.00	1	0
351	TULSA POWER - OK	Transmission		138.00	13.80	0.00	70.63	2	0
352	TULSA POWER - OK	Transmission		138.00	0.00	0.00	0.00	0	0
353	TULSA POWER - OK	Distribution		138.00	0.00	0.00	0.00	0	0
354	TULSA POWER - OK	Distribution		138.00	69.00	13.80	140.00	1	0
355	TULSA SOUTHEAST - OK	Distribution		138.00	65.92	13.20	50.00	1	0
356	TULSA SOUTHEAST - OK	Distribution		13.80	0.00	0.00	0.00	0	0
357	TULSA SOUTHEAST - OK	Distribution		138.00	69.00	13.20	33.00	1	0
358	TULSA SOUTHEAST - OK	Distribution		138.00	13.80	0.00	70.64	2	0
359	TULSA SUNRAY REF. - OK	Transmission		69.00	13.20	0.00	66.60	2	0
360	TULSA SUNRAY REF. - OK	Transmission		13.80	0.00	0.00	0.00	0	0
361	TULSA TRANS RESERVE - OK	Transmission		69.00	13.80	0.00	9.38	0	1
362	TULSA TRANS RESERVE - OK	Distribution		138.00	13.80	0.00	15.00	0	1
363	TULSA TRANS RESERVE - OK	Distribution		138.00	70.50	13.09	78.00	0	1
364	TULSA WILLIAMS PIPELINE C - OK	Distribution		69.00	4.16	2.40	6.25	1	0
365	TUTTLE - OK	Distribution		138.00	13.09	0.00	25.00	1	0
366	UNION AVENUE REFINERY - OK	Distribution		138.00	13.80	0.00	33.00	1	0
367	UTICA SQUARE - OK	Distribution		13.80	4.36	0.00	5.00	1	0
368	UTICA SQUARE - OK	Distribution		13.20	4.10	0.00	3.60	1	0
369	VALLIANT 345 - OK	Distribution		138.00	70.50	36.20	90.00	1	0

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)			
370	VALLIANT 345 - OK	Distribution		69.00	13.80	0.00	14.00	1	0
371	VALLIANT 345 - OK	Distribution		69.00	0.00	0.00	0.00	0	0
372	VALLIANT 345 - OK	Distribution		345.00	138.00	13.80	322.56	2	0
373	VALLIANT WEYCO - OK	Distribution		13.80	0.00	0.00	0.00	0	0
374	VALLIANT WEYCO - OK	Transmission		138.00	13.80	0.00	112.00	2	0
375	VALLIANT WEYCO #2 - OK	Transmission		138.00	13.80	0.00	106.00	2	0
376	VERDEN NATURAL GAS - OK	Transmission		138.00	4.10	0.00	22.40	1	0
377	VILLA GROVE - OK	Transmission		13.20	4.36	0.00	4.68	1	0
378	VINITA - OK	Distribution		13.80	0.00	0.00	0.00	0	0
379	VINITA - OK	Distribution		69.00	13.80	0.00	28.00	2	0
380	VINITA JUNCTION - OK	Distribution		138.00	69.00	13.80	50.00	1	0
381	VINITA JUNCTION - OK	Distribution		138.00	13.80	0.00	20.00	1	0
382	WAGONER - OK	Transmission		69.00	13.80	0.00	2.50	1	0
383	WALTERS JUNCTION - OK	Transmission		69.00	36.20	0.00	8.40	1	0
384	WAPANUCKA - OK	Transmission		138.00	4.36	0.00	40.00	2	0
385	WARREN MEDICAL CENTER - OK	Distribution		138.00	13.80	0.00	74.60	2	0
386	WARREN MEDICAL CENTER - OK	Distribution		13.80	0.00	0.00	0.00	0	0
387	WAURIKA - OK	Distribution		69.00	4.36	0.00	7.00	1	0
388	WEATHERFORD - OK	Distribution		138.00	13.80	0.00	22.40	1	0
389	WEATHERFORD - OK	Distribution		69.00	13.80	0.00	22.40	1	0
390	WEATHERFORD - OK	Distribution		13.80	0.00	0.00	0.00	0	0
391	WEATHERFORD JUNCTION - OK	Distribution		138.00	13.80	0.00	41.67	1	0
392	WEATHERFORD SE - OK	Distribution		138.00	66.00	13.80	50.00	1	0
393	WEKIWA - OK	Distribution		345.00	138.00	34.00	675.00	1	0
394	WEKIWA - OK	Distribution		138.00	13.80	0.00	22.40	1	0
395	WELEETKA POWER - OK	Distribution		138.00	66.00	13.80	100.00	2	0
396	WEST EDISON - OK	Distribution		138.00	13.80	0.00	74.60	2	0
397	WHIRLPOOL (PO) - OK	Distribution		138.00	13.80	0.00	14.00	1	0
398	WHITE CITY - OK	Distribution		13.20	4.30	0.00	9.36	2	0
399	WILBURTON - OK	Transmission		69.00	13.80	0.00	20.00	1	0
400	WILBURTON TRANSOK - OK	Transmission		138.00	4.16	0.00	7.50	1	0
401	WILDHORSE SHELL - OK	Transmission		138.00	4.16	0.00	5.01	3	0
402	WILLOW BRINKMAN - OK	Transmission		34.50	4.16	0.00	2.50	1	0
403	WOODLAND (PO) - OK	Transmission		13.20	4.16	0.00	5.00	1	0
404	WOODLAND (PO) - OK	Transmission		13.20	4.30	0.00	4.68	1	0
405	WRIGHT CITY - OK	Transmission		69.00	13.80	0.00	10.50	1	0
406	YALE AND ARCHER - OK	Transmission		13.20	4.36	0.00	6.25	1	0
407	YALE AND ARCHER - OK	Transmission		138.00	13.80	0.00	74.60	2	0
408	ZUNIS - OK	Transmission		13.80	0.00	0.00	0.00	0	0
409	ZUNIS - OK	Transmission		138.00	13.80	0.00	37.30	1	0
410	ZUNIS - OK	Transmission		138.00	13.80	0.00	20.00	1	0
411	ZUNIS - OK	Transmission		13.20	4.16	0.00	9.38	1	0
412	OKLAUNION 345-PSO - TX	Distribution		345.00	0.00	0.00	0.00	0	0
413	TotalDistributionSubstationMember								
414	TotalTransmissionSubstationMember								
415	Total								

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1		0	0.00
2		0	0.00
3		0	0.00
4		0	0.00
5	STATCAP	1	6,300.00
6		0	0.00
7		0	0.00
8		0	0.00
9		0	0.00
10		0	0.00
11		0	0.00
12		0	0.00
13		0	0.00
14		0	0.00
15		0	0.00
16		0	0.00
17		0	0.00
18		0	0.00
19	STATCAP	1	7.20
20		0	0.00
21		0	0.00
22	STATCAP	1	6.00
23		0	0.00
24	STATCAP	1	28.80
25		0	0.00
26		0	0.00
27		0	0.00
28		0	0.00
29		0	0.00
30	STATCAP	1	1.20
31		0	0.00
32		0	0.00
33		0	0.00
34		0	0.00
35		0	0.00
36		0	0.00
37		0	0.00
38		0	0.00
39		0	0.00
40		0	0.00
41		0	0.00
42	STATCAP	1	9.60
43	STATCAP	2	19.20
44		0	0.00
45		0	0.00
46	STATCAP	4	38.40
47	Air Core Reactor	1	0.00
48		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
49		0	0.00
50		0	0.00
51		0	0.00
52		0	0.00
53	STATCAP	1	6.00
54		0	0.00
55	STATCAP	1	6.00
56		0	0.00
57		0	0.00
58		0	0.00
59		0	0.00
60	STATCAP	1	6.00
61		0	0.00
62		0	0.00
63		0	0.00
64	50A Air-Core Reactor	1	0.00
65		0	0.00
66		0	0.00
67		0	0.00
68		0	0.00
69	STATCAP	1	28.80
70		0	0.00
71		0	0.00
72		0	0.00
73		0	0.00
74		0	0.00
75		0	0.00
76		0	0.00
77	STATCAP	1	9.60
78		0	0.00
79		0	0.00
80		0	0.00
81		0	0.00
82		0	0.00
83		0	0.00
84		0	0.00
85		0	0.00
86		0	0.00
87		0	0.00
88		0	0.00
89		0	0.00
90	STATCAP	1	57.60
91		0	0.00
92		0	0.00
93		0	0.00
94		0	0.00
95		0	0.00
96		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
97		0	0.00
98		0	0.00
99		0	0.00
100		0	0.00
101		0	0.00
102	STATCAP	2	9.60
103		0	0.00
104		0	0.00
105	STATCAP	1	6.00
106		0	0.00
107		0	0.00
108		0	0.00
109		0	0.00
110		0	0.00
111		0	0.00
112		0	0.00
113		0	0.00
114		0	0.00
115		0	0.00
116		0	0.00
117		0	0.00
118		0	0.00
119		0	0.00
120		0	0.00
121		0	0.00
122		0	0.00
123		0	0.00
124		0	0.00
125		0	0.00
126		0	0.00
127		0	0.00
128		0	0.00
129		0	0.00
130		0	0.00
131	STATCAP	3	18.00
132		0	0.00
133		0	0.00
134		0	0.00
135		0	0.00
136		0	0.00
137		0	0.00
138		0	0.00
139	STATCAP	1	6.30
140		0	0.00
141		0	0.00
142		0	0.00
143		0	0.00
144		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
145		0	0.00
146		0	0.00
147		0	0.00
148		0	0.00
149		0	0.00
150		0	0.00
151		0	0.00
152		0	0.00
153	STATCAP	1	8.40
154		0	0.00
155		0	0.00
156		0	0.00
157		0	0.00
158		0	0.00
159		0	0.00
160		0	0.00
161	STATCAP	1	23.00
162	XSLR - 0.6mH / 480A	3	0.00
163		0	0.00
164		0	0.00
165		0	0.00
166		0	0.00
167		0	0.00
168		0	0.00
169		0	0.00
170		0	0.00
171		0	0.00
172		0	0.00
173		0	0.00
174		0	0.00
175		0	0.00
176		0	0.00
177		0	0.00
178		0	0.00
179		0	0.00
180		0	0.00
181		0	0.00
182		0	0.00
183		0	0.00
184	STATCAP	2	9.60
185		0	0.00
186		0	0.00
187		0	0.00
188	STATCAP	3	18.00
189		0	0.00
190		0	0.00
191		0	0.00
192		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
193		0	0.00
194		0	0.00
195		0	0.00
196		0	0.00
197		0	0.00
198		0	0.00
199		0	0.00
200		0	0.00
201		0	0.00
202		0	0.00
203		0	0.00
204		0	0.00
205		0	0.00
206		0	0.00
207		0	0.00
208		0	0.00
209		0	0.00
210		0	0.00
211		0	0.00
212	Air Core Reactor	6	57.40
213		0	0.00
214		0	0.00
215		0	0.00
216		0	0.00
217	STATCAP	2	7.20
218		0	0.00
219		0	0.00
220	STATCAP	1	6.00
221		0	0.00
222		0	0.00
223		0	0.00
224		0	0.00
225		0	0.00
226		0	0.00
227		0	0.00
228		0	0.00
229		0	0.00
230		0	0.00
231	STATCAP	1	9.60
232		0	0.00
233		0	0.00
234		0	0.00
235		0	0.00
236		0	0.00
237		0	0.00
238		0	0.00
239		0	0.00
240		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
241	STATCAP	1	7.20
242		0	0.00
243		0	0.00
244	STATCAP	2	15.60
245		0	0.00
246		0	0.00
247		0	0.00
248		0	0.00
249		0	0.00
250		0	0.00
251		0	0.00
252	STATCAP	2	12.00
253		0	0.00
254		0	0.00
255		0	0.00
256		0	0.00
257		0	0.00
258		0	0.00
259	STATCAP	1	6.00
260		0	0.00
261		0	0.00
262		0	0.00
263		0	0.00
264		0	0.00
265		0	0.00
266		0	0.00
267		0	0.00
268		0	0.00
269		0	0.00
270		0	0.00
271	STATCAP	2	14.40
272		0	0.00
273		0	0.00
274		0	0.00
275		0	0.00
276	Air Core Reactor	6	0.00
277		0	0.00
278	STATCAP	2	0.00
279	STATCAP	1	0.00
280		0	0.00
281		0	0.00
282		0	0.00
283		0	0.00
284		0	0.00
285		0	0.00
286		0	0.00
287		0	0.00
288		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
289	STATCAP	1	6.00
290		0	0.00
291		0	0.00
292		0	0.00
293		0	0.00
294		0	0.00
295		0	0.00
296		0	0.00
297	STATCAP	2	15.17
298		0	0.00
299		0	0.00
300		0	0.00
301		0	0.00
302	STATCAP	2	7.20
303		0	0.00
304		0	0.00
305		0	0.00
306		0	0.00
307		0	0.00
308		0	0.00
309		0	0.00
310		0	0.00
311		0	0.00
312		0	0.00
313		0	0.00
314		0	0.00
315		0	0.00
316		0	0.00
317		0	0.00
318	STATCAP	1	14.40
319		0	0.00
320		0	0.00
321		0	0.00
322		0	0.00
323	Air Core Reactor	3	0.00
324		0	0.00
325		0	0.00
326		0	0.00
327	STATCAP	1	6.00
328		0	0.00
329		0	0.00
330		0	0.00
331		0	0.00
332		0	0.00
333		0	0.00
334		0	0.00
335		0	0.00
336		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
337		0	0.00
338		0	0.00
339		0	0.00
340		0	0.00
341	STATCAP	1	9.60
342		0	0.00
343		0	0.00
344		0	0.00
345		0	0.00
346		0	0.00
347	STATCAP	1	5.00
348		0	0.00
349		0	0.00
350		0	0.00
351		0	0.00
352	STATCAP	2	115.20
353	Air Core Reactor	3	0.00
354		0	0.00
355		0	0.00
356	STATCAP	3	18.00
357		0	0.00
358		0	0.00
359		0	0.00
360	STATCAP	2	12.00
361		0	0.00
362		0	0.00
363		0	0.00
364		0	0.00
365		0	0.00
366		0	0.00
367		0	0.00
368		0	0.00
369		0	0.00
370		0	0.00
371	STATCAP	1	19.20
372		0	0.00
373	STATCAP	2	13.20
374		0	0.00
375		0	0.00
376		0	0.00
377		0	0.00
378	STATCAP	1	6.00
379		0	0.00
380		0	0.00
381		0	0.00
382		0	0.00
383		0	0.00
384		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
385		0	0.00
386	STATCAP	1	6.00
387		0	0.00
388		0	0.00
389		0	0.00
390	STATCAP	1	6.00
391		0	0.00
392		0	0.00
393		0	0.00
394		0	0.00
395		0	0.00
396		0	0.00
397		0	0.00
398		0	0.00
399		0	0.00
400		0	0.00
401		0	0.00
402		0	0.00
403		0	0.00
404		0	0.00
405		0	0.00
406		0	0.00
407		0	0.00
408	STATCAP	2	12.00
409		0	0.00
410		0	0.00
411		0	0.00
412	REACTOR	1	50.00
413			507.27
414			6,572.40
415			7,079.67

Name of Respondent: Public Service Company of Oklahoma	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	Administrative and General Expenses - Maintenance	[a] AEPSC	935	3,500,671
3	Materials and Supplies	AEP Texas	154	1,586,634
4	Physical & Cyber Security	AEPSC	920, 923	598,496
5	Administrative and General Expenses - Operation	AEPSC	920, 921, 922, 923, 925, 926, 928, 930.1, 930.2, 931	2,796,958
6	Materials and Supplies	ETT	154	289,379
7	Rail Car Lease	I&M	186	285,912
8	Audit Services	AEPSC	920,923	646,300
9	Materials and Supplies	OKTCo	154	4,496,271
10	Rail Car Lease	SWEPCo	186	420,463
11	Building and Property Leases	OKTCo	567, 589	2,250,289
12	Materials and Supplies	OPCo	154	357,538
13	Rail Car Maintenance	AEGCo	151	418,893
14	Central Machine Shop	APCo	107, 108, 500, 511, 512, 513, 514, 531, 546, 549, 553	1,040,351
15	Materials and Supplies	SWEPCo	154	1,111,584
16	Steam Power Generation - Maintenance	AEPSC	510, 511, 512, 513, 514	927,477
17	Central Maintenance Facility	SWEPCo	107, 108, 512, 513	887,196
18	Steam Power Generation - Operation	AEPSC	500, 501, 502, 506, 508	11,422,188
19	Transmission Expenses - Maintenance	OKTCo	568, 569, 570, 571, 573	912,595
20	Civil & Political Activities & Other Services	AEPSC	426	712,733
21	Supply Chain & Fleet and Property Management	AEPSC	920, 923	1,865,471
22	Transmission Expenses - Operation	OKTCo	560, 562, 563, 566	2,126,605
23	Corp Safety & Health	AEPSC	920, 923	1,777,250
24	Services for Jointly Owned Facility - North Central Wind	SWEPCO	107, 108, 186, 408.1, 421, 426.1, 426.3, 426.4, 426.5, 431, 500, 501, 502, 506, 510, 546, 548, 549, 550, 553, 556, 557, 560, 561.2, 561.5, 563, 565, 566, 568, 569, 569.2, 570, 571, 573, 580, 587, 588, 920, 921, 922, 923, 924, 925, 926, 928, 930.1, 930.2, 931, 935	42,979,559
25	Tax Services	AEPSC	920, 923	697,862
26	Construction Services	AEP Texas	107, 108	280,119
27	Transmission Expenses - Maintenance	AEPSC	568, 569, 569.1, 569.2, 570, 571, 572, 573	831,707
28	Construction Services	AEPSC	107, 108	61,182,098
29	Transmission Expenses - Operation	AEPSC	560, 561.2, 561.3, 561.5, 561.6, 562, 563, 566, 920, 923	5,938,512
30	Construction Services	OPCo	107, 108	565,078
31	Treasury & Risk	AEPSC	920, 923	2,555,161
32	Corporate Accounting	AEPSC	920,923	1,533,606

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)
33	Corporate Planning & Budgeting	AEPSC	920, 923	1,488,206
34	Current and Accrued Liabilities	KPCo	244	1,227,521
35	Non-power Goods or Services Provided for Affiliate			
36	Current and Accrued Liabilities	SWEPCO	232	975,000
37	Customer Accounts Expenses	AEPSC	901, 902, 903, 904, 905	11,884,612
38	Distribution Expenses - Maintenance	AEP Texas	592, 593, 594, 595	385,468
39	Distribution Expenses - Maintenance	AEPSC	590, 591,, 592, 593, 594, 595, 597, 598	349,166
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Distribution Expenses - Maintenance	OPCo	593, 594, 595, 596	1,181,546
22	Distribution Expenses - Operation	AEPSC	580, 581, 582, 583, 584, 586, 587, 588	2,923,861
23	Environmental Services	AEPSC	920, 923	691,604
24	Factored Customer A/R Bad Debts	AEP Credit, Inc	426.5	3,846,916
25	Non-power Goods or Services Provided by Affiliated			
26	Factored Customer A/R Expense	AEP Credit, Inc	426.5	11,411,572
27	Federal Affairs	AEPSC	920, 923	498,231
28	Fuel & Storeroom Services	AEPSC	152, 163, 163.1	5,692,016
29	Human Resources	AEPSC	920, 923	3,249,436
30	HVDC North Tie	AEP Texas	566, 573, 925, 926	1,524,714
31	Information Technology	AEPSC	920, 923	6,353,250
32	Infrastructure Ops & Support	AEPSC	920, 923	802,518
33	Legal GC/Administration	AEPSC	920, 923	2,908,841
34	Non-power Goods or Services Provided for Affiliate			
42				
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Name of Respondent: Public Service Company of Oklahoma	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: NameOfAssociatedAffiliatedCompany

Affiliated Companies shown in Column (B):
AEP Credit, Inc. - AEP Credit, Inc.
AEP Texas - AEP Texas, Inc
AEPSC - American Electric Power Service Corporation
APCo - Appalachian Power Company
OKTCo - AEP Oklahoma Transmission Company, Inc
OPCo - Ohio Power Company
SWEPCo - Southwestern Electric Power Company
I&M - Indiana Michigan Power Company
ETT - Electric Transmission TX, LLC

AEPSC Allocations

Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

FLEET Allocations (Various)

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.