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)	Year/Period of Report
Portland General Electric Company	End of: 2023/ Q4

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

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

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

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

III. What and Where to Submit

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

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

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

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

   The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. When to Submit

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

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

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

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

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

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

"Sec. 304.

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

"Sec. 309.

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

GENERAL PENALTIES

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

FERC FORM NO. 1 (ED. 03-07)

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER	
IDENTIFICATION	
01 Exact Legal Name of Respondent Portland General Electric Company	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) 121 SW Salmon Street, Portland, Oregon, 97204	

05 Name of Contact Person Ryan Van Oostrum		06 Title of Contact Person Controller
07 Address of Contact Person (Street, City, State, Zip Code) 121 SW Salmon Street, Portland, Oregon, 97204		
08 Telephone of Contact Person, Including Area Code (503) 464-8426	09 This Report is An Original / A Resubmission (1) An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr) 04/18/2024

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 Joseph R. Trpik	03 Signature Joseph R. Trpik	04 Date Signed (Mo, Da, Yr) 04/18/2024
02 Title Senior Vice President, Finance and Chief Financial Officer		

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.

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

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)
	Identification	1	
	List of Schedules	2	
1	**General Information**	101	
2	**Control Over Respondent**	102	none
3	**Corporations Controlled by Respondent**	103	
4	**Officers**	104	
5	**Directors**	105	
6	**Information on Formula Rates**	106	not applicable
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
9	**Statement of Income for the Year**	114	
10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
13	**Statement of Accum Other Comp Income, Comp Income, and Hedging Activities**	122a	
14	**Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep**	200	
15	**Nuclear Fuel Materials**	202	none

16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	none
18	**Electric Plant Held for Future Use**	214	
19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	
22	**Materials and Supplies**	227	
23	**Allowances**	228	
24	**Extraordinary Property Losses**	230a	none
25	**Unrecovered Plant and Regulatory Study Costs**	230b	
26	**Transmission Service and Generation Interconnection Study Costs**	231	
27	**Other Regulatory Assets**	232	
28	**Miscellaneous Deferred Debits**	233	
29	**Accumulated Deferred Income Taxes**	234	
30	**Capital Stock**	250	
31	**Other Paid-in Capital**	253	
32	**Capital Stock Expense**	254b	
33	**Long-Term Debt**	256	
34	**Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax**	261	
35	**Taxes Accrued, Prepaid and Charged During the Year**	262	
36	**Accumulated Deferred Investment Tax Credits**	266	none
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	none
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	none
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	not applicable
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	none

57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	not applicable
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	none
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	none
66.2	**Energy Storage Operations (Small Plants)**	419	
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		

FERC FORM No. 1 (ED. 12-96)

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Portland General Electric Company	(1) An Original (2) A Resubmission	04/18/2024	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.

-

Ryan Van Oostrum

Controller

121 SW Salmon Street Portland, OR 97204

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.

-

State of Incorporation: OR

Date of Incorporation: 1930-07-25

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.

Property of respondent was not so held during the year.

(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 respondent is engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The respondent also participates in the wholesale market by purchasing and selling electricity and natrual gas in an effort to obtain reasonably-priced power to serve its retail customers.

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: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has purchased the headquarters complex in Portland, Oregon and leases the complex to the Respondent	100%	
2	World Trade Center Northwest Corporation (A wholly-owned subsidiary of 121 SW Salmon Street Corporation)	Company is the holder of the World Trade Center Franchise	100%	
3	Salmon Springs Hospitality Group, Inc.	Company provides food catering services	100%	
4	121 SW Salmon Street LLC			
5	Portland Renewable Resource Company LLC			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	President and Chief Executive Officer	Maria M. Pope	[(a)]1,144,080		
2	Senior Vice President of Finance, Chief Financial Officer and Treasurer	James A. Ajello	451,104		2023-08-31
3	Vice President Strategy Regulation and Energy Supply	Brett Sims	398,109		
4	Vice President, Utility Operations	Bradley Y. Jenkins	136,193		2023-04-27
5	Senior Vice President, Advanced Energy Delivery	Larry N. Bekkedahl	486,808		
6	Vice President, Information Technology and Chief Information Officer	John Kochavatr	506,447		

7	Vice President, Human Resources, Diversity, Equity and Inclusion	Anne E. Mersereau	436,501		
8	Vice President, Public Policy, Government Affairs and Communiations	Nicholas G. Blosser	368,990		2023-12-31
9	Senior Vice President, Chief Legal and Compliance Officer	Angelica Espinosa	511,432		
10	Executive Vice President, Chief Operating Officer	Benjamin Felton	487,500	2023-04-03	
11	Senior Vice President and Chief Financial Officer	Joseph Trpik	302,308	2023-06-30	

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OfficerSalary

Amounts shown in column (c) consist of salaries only.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	[a] Rodney L. Brown, Jr.	Portland, Oregon		
2	[b] Jack E. Davis Chair of the Board	Portland, Oregon		
3	Mark B. Ganz	Portland, Oregon		
4	Kathryn J. Jackson	Portland, Oregon		
5	M. Lee Pelton	Portland, Oregon		
6	Maria M. Pope President and Chief Executive Officer	Portland, Oregon		
7	Marie Oh Huber	Portland, Oregon		
8	Michael H. Millegan	Portland, Oregon		
9	Michael L. Lewis	Portland, Oregon		
10	James P. Torgerson Chair of the Board	Portland, Oregon		
11	Dawn L. Farrell	Portland, Oregon		
12	Patricia S. Pineda	Portland, Oregon		
13	[c] John O'Leary	Portland, Oregon		

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

Term Ended April 20, 2023
(b) Concept: NameAndTitleOfDirector
Term Ended April 20, 2023
(c) Concept: NameAndTitleOfDirector
Term began January 1, 2024

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the Federal Energy Regulatory Commission (FERC), on January 18, 2024, issued an order in Docket No. ES24-17-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2026. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

In August 2023, PGE amended its existing revolving credit facility. As of December 31, 2023, PGE had a $750 million revolving credit facility scheduled to expire in September 2028. The Company has the ability to expand the revolving credit facility to $850 million, if needed. Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, including as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on the Company's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2023, PGE was in compliance with this covenant with a 56.2% debt to total capital ratio. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. The Company believes these potential adjustments will have an immaterial impact on PGE's results of operations.

Under the revolving credit facility, as of December 31, 2023, PGE had no borrowings outstanding and there were no letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $750 million however, as PGE has elected to limit its borrowings to cover any potential need to repay outstanding commercial paper, the elected available credit capacity is $604 million.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2023, PGE had $146 million commercial paper outstanding.

PGE typically classifies any borrowings under the revolving credit facility and outstanding commercial paper as Notes Payable on the Comparative Balance Sheet.

In addition, PGE has four letter of credit facilities that provide a total capacity of $320 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, a total of $106 million of letters of credit were outstanding as of December 31, 2023. Letters of credit issued are not reflected on the Company's Comparative Balance Sheet.

On August 29, 2023, PGE entered into a Bond Purchase Agreement related to the sale of $500 million in First Mortgage Bonds (FMBs), the bonds consist of:

- a series, due in 2030, in the amount of $50 million that bear interest at an annual rate of 5.44%;
- a series, due in 2033, in the amount of $150 million that bear interest at an annual rate of 5.48%;
- a series, due in 2038, in the amount of $100 million that bear interest at an annual rate of 5.68%;
- a series due in 2053, in the amount of $100 million that bear interest at an annual rate of 5.78%; and
- a series due in 2059, in the amount of $100 million that bear interest at an annual rate of 5.83%.

As of December 31, 2023, all series, totaling $500 million, were issued and funded in full.

On November 30, 2022, PGE entered into a Bond Purchase Agreement related to the sale of $200 million in FMBs, the first half of which funded in 2022 and the remaining $100 million funded in full on January 13, 2023.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs.

On October 21, 2022, PGE obtained a 366-day term loan from lenders in the aggregate principal of $260 million under a 366-Day Bridge Credit Agreement. The term loan bore interest for the relevant interest period at the Term Secured Overnight Financing Rate (SOFR) plus Term SOFR Adjustment Rate of 10 basis points and Applicable Margin of 87.5 basis points. The interest rate was subject to adjustment pursuant to the terms of the loan. On March 1, 2023, this term loan was repaid in full. The term loan was classified as Other Long Term Debt on PGE's Comparative Balance Sheet.

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. In connection with the agreement to transfer certain tax credits generated in 2023, PGE provided indemnification against the buyer's losses related to a failure to satisfy the Production Tax Credits qualification or transferability requirements under the Internal Revenue Code, but not due to the action or legal tax status of the buyer or a change in tax law. As of December 31, 2023, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

7. None

8. None

9. Legal Proceedings:

Governmental Investigations

In March, April and May 2021, the Division of Enforcement of the Commodity Futures Trading Commission (the "CFTC"), the Division of Enforcement of the Securities and Exchange Commission (SEC), and the Division of Enforcement of the FERC, respectively, informed the Company they are conducting investigations arising out of the energy trading losses the Company previously announced in August 2020. The Company is cooperating with the CFTC, the SEC, and the FERC. Management cannot at this time predict the eventual scope or outcome of these matters.

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip, which is operated by one of the co-owners, Talen Montana, LLC (Talen). On May 10, 2022, Talen's parent company, Talen Energy Supply, LLC, filed for chapter 11 bankruptcy protection, although Colstrip continues to operate and generate electricity for PGE customers and others. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. An arbitration process has been initiated to address such business disagreements and has resulted in several legal proceedings. These legal proceedings, as well as other matters related to Colstrip, are summarized below.

*Arbitration*In March 2021, co-owner NorthWestern Corporation (NorthWestern) initiated arbitration against all other co-owners of Colstrip to determine whether co-owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or, alternatively, whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. The parties had agreed to stay the arbitration through April 1, 2024, and are now in the process of reengaging in arbitration discussions. An arbitration date has not yet been scheduled. PGE cannot predict the ultimate outcome of the arbitration process.

*Petition to compel arbitration*In April 2021, co-owners Avista Corporation, Puget Sound Energy Inc., PacifiCorp, and PGE (the Petitioners) petitioned in Spokane County Superior Court, Washington, Case No. 21201000-32, against NorthWestern and Talen to compel the arbitration initiated by NorthWestern that is described above. In May 2021, Talen removed the case to Federal Court (Eastern District of Washington Case No. 2:21-cv-00163-RMP). Following a hearing in July 2021, Talen's motion to transfer the case to the U.S. District Court for the District of Montana was granted. On August 10, 2023, the court dismissed the matter with prejudice pursuant to the parties' stipulation.

*Challenge to constitutionality of Montana Senate Bills 265 and 266 (MSB 265 and MSB 266)*On May 4, 2021, the Petitioners filed a claim against NorthWestern and Talen (the Defendants) in U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00047-SPW-KLD, based on the passage of MSB 265, which attempted to void contractual arbitration provisions within the O&O Agreement if they do not provide for three arbitrators or provide for venue outside of the county where the plant is located. The Petitioners filed a First Amended Complaint on May 19, 2021, adding the Attorney General of Montana (Montana AG) as defendant and challenging the constitutionality of MSB 266, which purportedly gives the Montana AG authority to penalize and restrain any co-owner of Colstrip who takes steps to shut-down the plant without unanimous consent, and authority to penalize any co-owner who fails or refuses to pay the costs to maintain the plant.

The Petitioners filed motions for their claims and on September 29, 2022, the Magistrate Judge issued Findings and Recommendations, which were adopted in full by the Court on October 19, 2022, granting the summary judgment motions by finding that MSB 266 was unconstitutional, and MSB 265 was unconstitutional and in the alternative preempted by the Federal Arbitration Act.

*Complaint to implement Montana Senate Bill 265 (MSB 265)*On May 4, 2021, Talen filed a complaint against the Petitioners and NorthWestern, in the Thirteenth Judicial District Court in the State of Montana, as an attempt to implement Montana laws when determining the language of the O&O Agreement based on the recent enactment of MSB 265. The case was subsequently removed to the U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00058-SPW-TJC. On August 10, 2023, the court dismissed the matter with prejudice pursuant to the parties' stipulation.

*Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al*In December 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. In August 2021, the claim was amended to add PGE as a defendant. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court. This matter was stayed for a time as a result of the bankruptcy filing of Talen's parent company, but litigation has resumed and the parties are working through discovery issues. The Court has entered a procedural schedule that leads to a trial, which would begin November 5, 2024. The Company is unable to predict outcome of this matter.

10. None

11. (Reserved)

12. None

13. Changes in Officers:

Benjamin Felton was appointed Executive Vice President, Chief Operating Officer, effective April 3, 2023.

Brad Jenkins, Vice President, Utility Operations, retired effective April 27, 2023.

Angelica Espinosa was promoted to Senior Vice President, Chief Legal and Compliance Officer effective June 7, 2023.

James A. Ajello, Senior Vice President Finance, Chief Financial Officer, Treasurer and Corporate Compliance Officer retired from his positions effective June 30, 2023.

Joseph Trpik was appointed Senior Vice President and Chief Financial Officer effective June 30, 2023.

Nicholas G. Blosser resigned as Vice President, Public Policy, Government Affairs and Communications effective December 31, 2023.

Changes in Directors:

The number of directors on the Board decreased from twelve to ten effective as of the 2023 annual shareholder's meeting held on April 21, 2023, at which time, Jack Davis and Rodney Brown retired from the Board.

14. None

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	13,294,752,697	12,403,927,120
3	Construction Work in Progress (107)	200	974,517,848	479,229,849
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		14,269,270,545	12,883,156,969
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,851,760,350	5,495,106,410
6	Net Utility Plant (Enter Total of line 4 less 5)		8,417,510,195	7,388,050,559
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		8,417,510,195	7,388,050,559
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,916,261	2,870,226
19	(Less) Accum. Prov. for Depr. and Amort. (122)		511,360	465,486
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224	84,967,379	83,892,347
23	Noncurrent Portion of Allowances	228	0	0
24	Other Investments (124)		9,097,650	5,923,767
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		73,077,737	80,794,848
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		11,107,353	73,435,140
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		180,655,020	246,450,842
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,569,354	15,666,550
36	Special Deposits (132-134)		92,079,229	116,528,103
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		96,842	150,000,001
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		219,789,679	219,473,279
41	Other Accounts Receivable (143)		64,204,830	58,776,357
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,443,726	12,085,787
43	Notes Receivable from Associated Companies (145)		0	0

44	Accounts Receivable from Assoc. Companies (146)		1,890,454	1,351,058
45	Fuel Stock (151)	227	28,001,414	29,151,034
46	Fuel Stock Expenses Undistributed (152)	227	0	1,378
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	78,836,409	60,023,704
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202/227	0	0
52	Allowances (158.1 and 158.2)	228	2,111,148	3,023,770
53	(Less) Noncurrent Portion of Allowances	228	0	0
54	Stores Expense Undistributed (163)	227	3,950,888	2,754,586
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		78,543,398	80,855,866
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		138,282,759	131,856,462
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		32,622,968	386,616,225
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		11,107,353	73,435,140
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		724,428,293	1,170,557,446
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,455,185	12,510,845
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	138,708,705	132,510,020
72	Other Regulatory Assets (182.3)	232	613,582,050	434,088,731
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,537,042	1,980,265
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		14,768	0
77	Temporary Facilities (185)		0	24,702
78	Miscellaneous Deferred Debits (186)	233	8,502,469	9,736,583
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352	0	0
81	Unamortized Loss on Reaquired Debt (189)		16,085,911	17,340,512
82	Accumulated Deferred Income Taxes (190)	234	573,553,162	640,683,198
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,367,439,292	1,248,874,856

85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,690,032,800	10,053,933,703

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	1,753,903,725	1,253,363,919
3	Preferred Stock Issued (204)	250	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	18,789,718	18,789,718
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	23,113,532	23,113,532
11	Retained Earnings (215, 215.1, 216)	118	1,568,996,980	1,535,343,048
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	7,427,718	6,352,686
13	(Less) Reacquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(4,999,964)	(3,965,243)
16	Total Proprietary Capital (lines 2 through 15)		3,321,004,645	2,786,770,596
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	3,998,800,000	3,398,800,000
19	(Less) Reacquired Bonds (222)	256	0	0
20	Advances from Associated Companies (223)	256	0	0
21	Other Long-Term Debt (224)	256	0	260,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		305,471	329,866
24	Total Long-Term Debt (lines 18 through 23)		3,998,494,529	3,658,470,134
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		332,552,355	337,658,448
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		6,675,302	7,019,752
29	Accumulated Provision for Pensions and Benefits (228.3)		263,566,512	264,684,842
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		8,073,398	10,245,694
32	Long-Term Portion of Derivative Instrument Liabilities		74,459,595	75,471,084
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		285,151,269	289,128,195

35	Total Other Noncurrent Liabilities (lines 26 through 34)		970,478,431	984,208,015
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		145,811,136	0
38	Accounts Payable (232)		470,087,386	552,847,660
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		11,403,070	15,025,014
41	Customer Deposits (235)		25,601,775	154,738,250
42	Taxes Accrued (236)	262	12,211,988	12,258,338
43	Interest Accrued (237)		39,954,525	30,682,106
44	Dividends Declared (238)		50,595,253	42,454,026
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		22,492,203	18,743,334
48	Miscellaneous Current and Accrued Liabilities (242)		46,939,573	32,229,226
49	Obligations Under Capital Leases-Current (243)		24,913,668	26,983,721
50	Derivative Instrument Liabilities (244)		238,759,624	193,376,878
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		74,459,595	75,471,084
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,014,310,606	1,003,867,469
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266	497,448	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	36,787,807	28,268,513
60	Other Regulatory Liabilities (254)	278	286,202,265	511,529,098
61	Unamortized Gain on Reacquired Debt (257)		0	2,013
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		876,069,126	841,673,575
64	Accum. Deferred Income Taxes-Other (283)		186,187,943	239,144,290
65	Total Deferred Credits (lines 56 through 64)		1,385,744,589	1,620,617,489
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,690,032,800	10,053,933,703

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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 Utility 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	2,966,551,020	2,702,424,185			2,966,551,020	2,702,424,185		0		
3	Operating Expenses											
4	Operation Expenses (401)	320	1,739,144,236	1,536,397,416			1,739,144,236	1,536,397,416		0		
5	Maintenance Expenses (402)	320	222,811,863	203,629,987			222,811,863	203,629,987		0		
6	Depreciation Expense (403)	336	361,540,625	335,206,965			361,540,625	335,206,965		0		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	3,635,829	3,555,122			3,635,829	3,555,122		0		
8	Amort. & Depl. of Utility Plant (404-405)	336	65,864,461	60,100,949			65,864,461	60,100,949		0		
9	Amort. of Utility Plant Acq. Adj. (406)	336	0	0			0	0		0		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		(82,944)	283,290			(82,944)	283,290		0		
11	Amort. of Conversion Expenses (407.2)		0	0			0	0		0		
12	Regulatory Debits (407.3)		24,239,596	23,096,438			24,239,596	23,096,438		0		
13	(Less) Regulatory Credits (407.4)		3,402,683	15,271,896			3,402,683	15,271,896		0		
14	Taxes Other Than Income Taxes (408.1)	262	161,434,174	154,021,039			161,434,174	154,021,039		0		
15	Income Taxes - Federal (409.1)	262	9,247,886	9,567,596			9,247,886	9,567,596		0		
16	Income Taxes - Other (409.1)	262	25,127,505	23,960,867			25,127,505	23,960,867		0		
17	Provision for Deferred Income Taxes (410.1)	234, 272	471,976,889	346,448,410			471,976,889	346,448,410		0		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	466,804,780	342,334,727			466,804,780	342,334,727		0		
19	Investment Tax Credit Adj. - Net (411.4)	266	0	0			0	0		0		
20	(Less) Gains from Disp. of Utility Plant (411.6)		0	605,776			0	605,776		0		
21	Losses from Disp. of Utility Plant (411.7)		0	0			0	0		0		
22	(Less) Gains from Disposition of Allowances (411.8)		0	0			0	0		0		
23	Losses from Disposition of Allowances (411.9)		0	0			0	0		0		
24	Accretion Expense (411.10)		2,946,089	2,935,076			2,946,089	2,935,076		0		

25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,617,678,746	2,340,990,756			2,617,678,746	2,340,990,756	0	0	0	0
27	Net Util Oper Inc (Enter Tot line 2 less 25)		348,872,274	361,433,429			348,872,274	361,433,429	0	0	0	0
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)		0	4,040								
33	Revenues From Nonutility Operations (417)		2,900,050	3,412,801								
34	(Less) Expenses of Nonutility Operations (417.1)		5,101,217	5,086,681								
35	Nonoperating Rental Income (418)		221,616	383,537								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,075,032	691,455								
37	Interest and Dividend Income (419)		4,027,081	950,598								
38	Allowance for Other Funds Used During Construction (419.1)		19,200,081	13,599,123								
39	Miscellaneous Nonoperating Income (421)		16,263,135	10,402,354								
40	Gain on Disposition of Property (421.1)		0	24,765								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		38,585,778	24,373,912								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)			0								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		2,085,895	2,266,554								
46	Life Insurance (426.2)		(2,695,608)	4,228,435								
47	Penalties (426.3)		26,119	733								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,187,925	1,273,149								
49	Other Deductions (426.5)		4,974,782	549,573								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,579,113	8,318,444								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	427,618	365,294								
53	Income Taxes-Federal (409.2)	262	1,390,231	(908,375)								
54	Income Taxes-Other (409.2)	262	593,999	(386,463)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	4,895,268	5,809,155								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,279,544	3,717,411								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		5,027,572	1,162,200								
	Net Other Income and Deductions (Total											

60	of lines 41, 50, 59)		27,979,093	14,893,268		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		153,441,203	136,366,647		
63	Amort. of Debt Disc. and Expense (428)		1,593,767	1,192,613		
64	Amortization of Loss on Reaquired Debt (428.1)		1,260,409	1,594,761		
65	(Less) Amort. of Premium on Debt-Credit (429)		0	0		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		2,013	8,052		
67	Interest on Debt to Assoc. Companies (430)		0	0		
68	Other Interest Expense (431)		10,494,708	5,692,958		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,742,176	7,376,075		
70	Net Interest Charges (Total of lines 62 thru 69)		154,045,898	137,462,852		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		222,805,469	238,863,845		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0		
76	Income Taxes-Federal and Other (409.3)	262				
77	Extraordinary Items After Taxes (line 75 less line 76)		0	0		
78	Net Income (Total of line 71 and 77)		222,805,469	238,863,845		

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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		1,531,490,255	1,467,510,647
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			

4.1				
4.2				
4.3				
4.4				
4.5				
4.6				
4.7				
4.8				
4.9				
4.10				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Adjustments to Retained Earnings Debit. The amount of $13,212,451 represents the repurchase of common stock in February and March 2022.			(13,212,451)
10.2				
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
10.10				
15	TOTAL Debits to Retained Earnings (Acct. 439)		0	(13,212,451)
16	Balance Transferred from Income (Account 433 less Account 418.1)		221,730,437	238,172,389
17	Appropriations of Retained Earnings (Acct. 436)			
17.1				
17.2				
17.3				
17.4				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				
23.2				
23.3				
23.4				
23.5				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock (Acct. 438)	438	(188,076,505)	(160,980,330)
30.2				
30.3				
30.4				

30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(188,076,505)	(160,980,330)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,565,144,187	1,531,490,255
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				
39.2				
39.3				
39.4				
39.5				
39.6				
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)		3,852,793	3,852,793
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,793	3,852,793
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,568,996,980	1,535,343,048
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		6,352,686	5,661,231
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,075,032	691,455
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				
53	Balance-End of Year (Total lines 49 thru 52)		7,427,718	6,352,686

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)	222,805,469	238,863,845
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	431,040,915	398,863,036
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Discount	2,852,163	2,779,322
5.2	Amortization of Unrecovered Plant	(82,944)	283,290

5.3	Net Price Risk Management Activities	399,376,003	(193,036,223)
8	Deferred Income Taxes (Net)	7,787,833	6,205,427
9	Investment Tax Credit Adjustment (Net)	0	0
10	Net (Increase) Decrease in Receivables	8,219,063	(69,285,365)
11	Net (Increase) Decrease in Inventory	(17,945,387)	(17,400,671)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(177,058,522)	162,468,899
14	Net (Increase) Decrease in Other Regulatory Assets	(359,725,699)	186,268,489
15	Net Increase (Decrease) in Other Regulatory Liabilities	4,350,066	(27,791,356)
16	(Less) Allowance for Other Funds Used During Construction	19,200,081	13,599,123
17	(Less) Undistributed Earnings from Subsidiary Companies	1,075,032	691,455
18	Other (provide details in footnote):		
18.1	Other: Margin and Customer Deposits	(104,687,601)	2,444,639
18.2	Other: Operating	[(a)]15,510,800	[(c)]7,855,448
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	412,167,046	684,228,202
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,373,225,203)	(794,015,596)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(46,035)	(274,979)
30	(Less) Allowance for Other Funds Used During Construction	(19,200,081)	(13,599,123)
31	Other (provide details in footnote):		
31.1	Other Capital Activities	[(b)](10,646,117)	[(d)](10,434,410)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,364,717,274)	(791,125,862)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	0	0
39	Investments in and Advances to Assoc. and Subsidiary Companies	0	0
40	Contributions and Advances from Assoc. and Subsidiary Companies	0	0
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Sale of Property	2,029,983	13,444,593

53.2	Other Investments	6,318,294	3,635,238
53.3	Purchases of Trojan Decommissioning Securities	(654,830)	(3,061,326)
53.4	Sales of Trojan Decommissioning Securities	608,496	2,852,491
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,356,415,331)	(774,254,866)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	600,000,000	360,000,000
62	Preferred Stock		
63	Common Stock	479,821,663	(4,862,840)
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	145,811,136	0
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,225,632,799	355,137,160
72	Payments for Retirement of:		
73	Long-term Debt (b)	(260,000,000)	0
74	Preferred Stock		
75	Common Stock	0	(17,995,125)
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	0	[(e)]25,007,873
76.2	Debt Issue Costs	(3,334,540)	(994,911)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(179,050,329)	(157,729,263)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	783,247,930	203,425,734
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)	(161,000,355)	113,399,070
88	Cash and Cash Equivalents at Beginning of Period	165,666,551	52,267,481
90	Cash and Cash Equivalents at End of Period	4,666,196	165,666,551

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to stock compensation expense.

(b) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

(c) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to prepayments and stock compensation expense.

(d) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

(e) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Amounts relate to proceeds from the Pelton/Round Butte failed sale-leaseback transaction.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.

Supplemental Disclosures

Supplemental Information to Statement of Cash Flows

Reconciliation between "Cash and Cash Equivalents at Beginning/End of the Year" on Statement of Cash Flows with the related amounts on the Comparative Balance Sheet:

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 15,666,550	$ 4,569,354
Temporary Cash Investments (136)	150,000,001	96,842
	$ 165,666,551	$ 4,666,196

	2022	2023
Cash paid during the year:		
Interest	$ 135,072,765	$ 148,942,136
Allowance for borrowed funds used during construction	(7,376,075)	(12,742,176)
	$ 127,696,690	$ 136,199,960
Income taxes	$ 36,621,275	$ 11,535,794
Non-cash investing and financing activities:		
Accrued capital additions	$ 111,199,583	$ 212,428,061
Accrued dividends payable	$ 42,454,026	$ 50,595,253
Preliminary engineering transferred to Construction work in progress	$ 969,351	$ 513,239

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically-integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon (State). The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to meet the needs of, and obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. In addition, PGE performs portfolio management and wholesale market sales services for third parties in the region. The Company continues to develop products and service offerings for the benefit of retail and wholesale customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGE's corporate headquarters. The Company's corporate headquarters is located in Portland, Oregon and its approximately four thousand square mile, State-approved service area is located entirely within the State. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2023, PGE served approximately 934 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2023, PGE had 2,842 employees in its workforce, with 661 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. One agreement covers 596 employees and expires March 2025, and the other covers 65 employees and expires August 2027. PGE also utilizes independent contractors and temporary personnel to supplement its workforce.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Financial Statements

These financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). As a result, the presentation of these financial statements differs from GAAP.

The primary differences include the requirement that PGE report its investments in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. In addition, the FERC requires that certain items on the Comparative Balance Sheet be classified differently than that required by GAAP, primarily the classification of components of accumulated deferred income taxes, long-term debt, regulatory assets and liabilities, accumulated asset retirement removal costs, the non-service component of pension expense, operating leases, and implementation costs related to cloud computing arrangements.

The FERC also requires that certain items on the Statement of Income be classified differently than that required by GAAP. These include the requirement that all gains and losses on non-physical settlements of electricity derivative activities be recorded on a gross basis rather than on a net basis, as required by GAAP (for additional information, see Note 5 - Risk Management). In addition, certain items that are considered to be non-operating in nature are recorded in Other Income Deductions in the FERC Statement of Income but are recorded within Operating Expenses in financial statements prepared in accordance with GAAP.

For GAAP reporting, the portion of payments under capital lease obligations related to principal is recorded as a financing outflow and included in Net Cash Provided by (Used in) Financing Activities; however, the FERC Statement of Cash Flows includes such amounts on the Other line of Net Cash Provided by Operating Activities.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Subsequent Events

PGE has evaluated the impact of events occurring after December 31, 2023 up to February 20, 2024, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 18, 2024. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Temporary Cash Investments

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as Temporary Cash Investments, of which PGE had none as of December 31, 2023 and $150 million as of December 31, 2022 reflected in the Comparative Balance Sheet.

Customer Accounts Receivable

Customer Accounts Receivable are recorded at invoiced amounts based on prices that are subject to federal (FERC) and State (OPUC) regulations. Balances do not bear interest; however, late fees are assessed beginning 8 business days after the invoice due date. Accounts that are inactivated due to nonpayment are charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the due date of the final invoice. During 2020, 2021, and much of 2022, the Company took steps to support customers during the COVID-19 pandemic, including suspending late fees and developing time payment arrangements. COVID-19 protections ended in September 2022.

Provisions for Uncollectible Accounts and unbilled revenues related to retail sales are charged to Administrative and General Expenses and are recorded in the same period as the related revenues, with an offsetting credit to the Accumulated Provision for Uncollectible Accounts. Such estimates for credit losses are based on management's assessment of the current and forecasted probability of collection, aging of Customer Accounts Receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for Customer Accounts Receivable and unbilled revenues. For more information on PGE's Accumulated Provision for Uncollectible Accounts and unbilled revenues see "*Customer Accounts Receivable, Net*" in Note 3, Comparative Balance Sheet Components.

Provisions for Uncollectible Accounts related to wholesale sales are charged to Purchased Power and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of Customer Accounts Receivable related to wholesale sales in 2023 or 2022.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, future, swap, and option contracts for electricity, natural gas, and foreign currency. These instruments are measured at fair value and recorded on the Comparative Balance Sheet as assets or liabilities from price risk management activities. Changes in fair value are recognized in the Statement of Income, offset by the effects of regulatory accounting when it is expected that the gain or loss upon settlement will be reflected in future retail rates. Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load may meet the requirements for treatment under the normal purchases and normal sales scope exception. Such contracts are not recorded at fair value and are recognized under accrual accounting.

Price risk management activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net variable power costs (NVPC).

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, the Company recognizes a realized gain or loss on the derivative instrument.

Physically settled electricity and natural gas sale and purchase transactions are recorded in Operating Revenues and Purchased Power, respectively, upon settlement, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased Power upon financial settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are reflected as Special Deposits included within Current and Accrued Assets in the Comparative Balance Sheet and were $92 million as of December 31, 2023 and $116 million as of December 31, 2022. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $40 million and $33 million as of December 31, 2023 and 2022, respectively.

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities, as well as fuel, which includes natural gas, coal, and oil for use in the Company's generating plants. Periodically, the Company assesses inventory for purposes of determining that inventories are recorded at the lower of average cost or net realizable value.

Utility Plant

Capitalization Policy

Utility Plant is capitalized at original cost, which includes direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFUDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls performed under long-term service agreements at PGE's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining FERC licenses for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction Work In Progress in Utility Plant on the Comparative Balance Sheet. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, PGE may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFUDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. In 2020, the FERC issued a waiver that allowed jurisdictional utilities to apply an alternative AFUDC calculation formula that excluded the actual outstanding short-term debt balance and replaced it with the simple average of the actual 2019 short-term debt balance. PGE adopted the waiver in the second quarter of 2020. The purpose of the waiver, which ultimately expired March 31, 2022, was to allow relief from the detrimental impacts of issuing short-term debt on the allowance for equity funds used during construction in response to COVID-19.

AFUDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 6.5% in 2023 and in 2022, and 6.7% in 2021. AFUDC from borrowed funds, reflected as a reduction to Interest Charges was $13 million in 2023 and $7 million in 2022. AFUDC from equity funds, included in Other Income, was $19 million in 2023, $14 million in 2022, and $17 million in 2021.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation Expense as a percent of the related average depreciable plant in service was 3.4% in 2023 and 2022. A component of Depreciation Expense includes estimated asset retirement removal costs allowed in customer prices.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. In 2021, PGE completed a depreciation study based on 2019 data, with an order received from the OPUC in December 2021 authorizing new depreciation rates effective May 9, 2022.

Thermal generation plants are depreciated using a life-span methodology, which ensures that plant investment is recovered by the estimated retirement dates, which range from 2025 to 2061. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	95
Wind	30
Transmission	61
Distribution	51
General	16

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to Accumulated Provision for Depreciation, Amortization, and Depletion. Cost of removal expenditures are recorded against AROs or to Accumulated Provision for Depreciation, Amortization, and Depletion.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $558 million and $499 million as of December 31, 2023 and 2022, respectively, with amortization expense of $61 million in 2023 and $58 million in 2022. Future estimated amortization expense as of December 31, 2023 is as follows: $70 million in 2024; $58 million in 2025; $50 million in 2026; $45 million in 2027; and $24 million in 2028.

Marketable Securities

Nuclear decommissioning trust

Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) at the decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. The Nuclear decommissioning trust (NDT) includes contributions made by the Company, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust

Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans (NQBP) and represents contributions made by the Company, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

All of PGE's investments in marketable securities included in NDT and NQBP trust assets on the Comparative Balance Sheet, are classified as equity or trading debt securities. These securities are classified as noncurrent because they are not available for use in operations. Such securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the NQBP trust assets are included in Other Income. Realized and unrealized gains and losses on the NDT fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold in the NDT and the NQBP are based on the first in first out method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and regulatory liabilities. Regulatory assets represent: i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process; or ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as: i) prices are established by, or subject to, approval by independent third-party regulators; ii) prices are designed to recover the specific enterprise's cost-of-service; and iii) in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the Statement of Income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include: i) increased competition that restricts PGE's ability to establish prices to recover specific costs; and ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of PGE's regulatory assets is probable.

For additional information concerning the Company's regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a Power Cost Adjustment Mechanism (PCAM), as approved by the OPUC. Pursuant to the PCAM, future customer prices can be adjusted to reflect a portion of the difference between: i) NVPC forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC for the year. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased Power in the Company's Statement of Income, and is net of wholesale sales, which are classified as Operating Revenues in the Statement of Income.

The Company is subject to a portion of the business risk or benefit associated with the difference between actual and baseline NVPC by application of an asymmetrical deadband, which ranges from $15 million below to $30 million above baseline NVPC.

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.5% for 2023 and 2022.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating Revenues in PGE's Statement of Income, while any estimated collection from customers is recorded as a reduction in Purchased Power. For the year ended December 31, 2023, PGE's actual NVPC was $5 million above baseline NVPC, which is within the established deadband range, therefore no estimated collection from customers was recorded as of December 31, 2023. A final determination regarding the 2023 PCAM results will be made by the OPUC through a public filing and review in 2024. For the year ended December 31, 2022, actual NVPC was above baseline NVPC by $23 million, which was within the established deadband range, therefore no estimated collection from customers was recorded as of December 31, 2022.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's Comparative Balance Sheet. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques. The present value of estimated future decommissioning costs is capitalized and included in Net Utility Plant on the Comparative Balance Sheet with a corresponding offset to ARO. For revisions to AROs in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the Comparative Balance Sheet, except for those AROs related to non-utility assets which is charged to Miscellaneous Nonoperating Income (Acct 421) on the Statement of Income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, with such depreciation included in Depreciation and amortization in the Statement of Income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to Accretion Expense, which is included in Total Utility Operating Expenses in the Company's Statement of Income.

For additional information concerning the Company's AROs, see Note 7, Asset Retirement Obligations.

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's Comparative Balance Sheet. As of December 31, 2023, PGE had a net regulatory liability related to Utility Plant AROs in the amount of $4 million and a net regulatory asset related to Trojan decommissioning ARO activities of $139 million. As of December 31, 2022, PGE had a net regulatory liability related to Utility Plant AROs in the amount of $7 million and a net regulatory asset related to Trojan decommissioning ARO activities of $131 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 6, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. Loss contingencies, including environmental contingencies, are accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that a liability has been incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons why the estimate cannot be made.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in either the current or the subsequent reporting period, depending on the nature of the underlying event.

Gain contingencies are recognized when realized and are disclosed when material.

For additional information concerning the Company's contingencies, see Note 17, Contingencies.

Accumulated Other Comprehensive Loss

Accumulated other Comprehensive Loss (AOCL) presented on the Comparative Balance Sheet is comprised of the difference between the obligations of the non-qualified benefit plans recognized in net income and the unfunded position.

Revenue Recognition

Operating Revenues are recognized when obligations under the terms of a contract with customers are satisfied. Generally, this satisfaction of performance obligations and transfer of control occurs and Operating Revenues are recognized as electricity is delivered to customers, including any services provided. The prices charged, and amount of consideration PGE receives in exchange for its services provided, are regulated by the OPUC or the FERC. PGE recognizes revenue through the following steps: i) identifying the contract with the customer; ii) identifying the performance obligations in the contract; iii) determining the transaction price; iv) allocating the transaction price to the performance obligations; and v) recognizing revenue when or as each performance obligation is satisfied.

Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's Statement of Income. Amounts collected from customers are included in Operating Revenues and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $56 million in 2023 and $53 million in 2022.

Retail revenue is billed based on monthly meter readings taken at various cycle dates throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that remained unbilled to customers. The unbilled revenues estimate, which is classified as Accrued Utility Revenues, net in the Company's Comparative Balance Sheet, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

As a rate-regulated utility, PGE, in certain situations, recognizes Operating Revenues to be billed to customers in future periods or defers the recognition of certain Operating Revenues to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For additional information concerning the Company's Stock-Based Compensation, see Note 13, Stock-Based Compensation Expense.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Investment Tax Credits (ITC) are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized upon transfer or in future tax returns. Valuation allowances related to a discount incurred on transfer transactions that are recorded to deferred tax expense are currently recoverable through a regulatory asset.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's Comparative Balance Sheet.

PGE records any interest and penalties related to income tax deficiencies in Interest Charges and Miscellaneous Nonoperating Income, respectively, in the Statement of Income.

The Inflation Reduction Act of 2022 (IRA) was signed into law on August 16, 2022. The IRA provides an election to transfer (i.e., sell) certain tax credits to unrelated third parties in exchange for cash consideration. PGE is electing an accounting policy to account for the transfer of Production Tax Credits (PTCs) and ITCs, including discounts, within the scope of Accounting Standards Codification 740 - Income Taxes. On December 12, 2023, PGE received approval from the OPUC to transfer 2023 PTCs and record any difference in the full value and the discounted value as a deferred regulatory asset. Proceeds from the sale of 2023 PTCs are reported in Tax credit sales on PGE's Statement of Cash Flows. PGE transferred tax credits of $24 million, net of discount, for cash proceeds in the fourth quarter of 2023. Derecognition of the transferred deferred tax asset occurs when the buyer obtains control of the tax credit

Recent Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2023-07 *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*. ASU 2023-07 amends Topic 280 to improve reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2025. Early adoption is permitted. As the standard relates only to disclosures, PGE does not expect the adoption to have a material impact on the financial statements and does not plan to early adopt the standard.

NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

Accumulated Provision for Uncollectible Accounts

The following is the activity in the Accumulated Provision for Uncollectible Accounts (in millions):

	Years Ended December 31,	
	2023	2022
Balance as of beginning of year	$ 12	$ 26
(Decrease)/Increase in provision *	5	(2)
Amounts written off, less recoveries	(8)	(12)
Balance as of end of year	$ 9	$ 12

* Pursuant to the Company's COVID-19 deferral, certain decreases and increases in the Provision for Uncollectible Accounts have been deferred as a net Regulatory Asset. Of the amounts recorded as decreases and increases in the Provision for Uncollectible Accounts, reductions of $10 million for the year ended December 31, 2022 have been offset within the COVID-19 Regulatory Asset. See Note 6, Regulatory Assets and Liabilities for more information.

Net Utility Plant

Net Utility Plant consists of the following (in millions):

	As of December 31,	
	2023	2022
Utility Plant:		
Generation	$ 4,918	$ 4,660
Transmission	1,141	1,116
Distribution	5,251	4,813
General	977	950
Intangible	960	830
Total in service	13,247	12,369
Accumulated depreciation and amortization	(5,852)	(5,495)
Total in service, net	7,395	6,874
Held for future use	48	35
Construction Work In Progress *	975	479
Net Utility Plant	$ 8,418	$ 7,388

*The Clearwater Wind Project, with $411 million in CWIP, was placed in-service on January 5, 2024.

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's Comparative Balance Sheet, for which it is practicable to estimate fair value for each reporting period. The Company then classifies these financial assets and liabilities based on a fair value hierarchy applied to prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy and application to the Company are discussed below.

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the measurement date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement date.

Level 3 Pricing inputs include significant inputs that are unobservable for the asset or liability.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company'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. Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2023 and 2022, except those presented in this note.

The Company's financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	December 31, 2023				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary cash investments	$	$	$	$	$
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	9	9			18
Corporate credit		7			7
Money market funds measured at NAV (2)				6	6
Non-qualified benefit plan trust: (3)					
Money market funds	2				2
Equity securitiesdomestic					
Debt securitiesdomestic government	3				3
Paid Leave Oregon Trust:					
Money market funds measured at NAV (2)				3	3
Price risk management activities: (1) (4)					
Electricity		8	14		22
Natural gas		11			11
	$ 14	$ 35	$ 14	$ 9	$ 72
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$	$ 30	$ 43	$	$ 73
Natural gas		150	16		166
	$	$ 180	$ 59	$	$ 239

(1)Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities, as appropriate.
(2)Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3)Excludes insurance policies of $30 million, which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 5, Risk Management.

	December 31, 2022				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary cash investments	$ 150	$	$	$	$ 150
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	9	10			19
Corporate credit		9			9
Money market funds measured at NAV (2)				11	11
Non-qualified benefit plan trust: (3)					
Money market funds	1				1
Equity securitiesdomestic	3				3
Debt securitiesdomestic government	3				3
Price risk management activities: (1) (4)					
Electricity		93	63		156
Natural gas		225	6		231

	$ 166	$ 337	$ 69	$ 11	$ 583
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$	$ 53	$ 93	$	$ 146
Natural gas		39	8		47
	$	$ 92	$ 101	$	$ 193

(1)Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities, as appropriate.
(2)Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3)Excludes insurance policies of $31 million, which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 5, Risk Management.

Temporary cash investments are highly liquid investments with maturities of three months or less at the date of acquisition and primarily consist of money market funds. Such funds seek to maintain a stable net asset value and are comprised of short-term, government funds. Policies of such funds require that the weighted-average maturity of securities held by the funds do not exceed 90 days and investors have the ability to redeem shares daily at the net asset value of the respective fund. Temporary cash investments are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for money market fund prices include published exchanges such as the National Association of Securities Dealers Automated Quotations (NASDAQ) and the New York Stock Exchange (NYSE).

Assets held in the NDT, NQBP, and Paid Leave Oregon trusts are recorded at fair value as Other Special Funds in PGE's Comparative Balance Sheet and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

*Debt securities*PGE invests in highly-liquid United States Treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

*Equity securities*Equity mutual fund and common stock securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the NYSE.

*Money market funds*PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value. Redemption is permitted daily without written notice.

The NQBP trust is invested in exchange traded government money market funds and is classified as Level 1 in the fair value hierarchy due to the availability of quoted prices in published exchanges such as NASDAQ and the NYSE. The money market fund in the NDT is valued at NAV as a practical expedient and is not included in the fair value hierarchy.

Assets and liabilities from price risk management activities, recorded at fair value in PGE's Comparative Balance Sheet, consist of derivative instruments entered into by the Company to manage its risk exposure to commodity price and foreign currency exchange rates and reduce volatility in NVPC. For additional information regarding these assets and liabilities, see Note 5, Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as forward commodity prices and interest rates. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include commodity forwards, futures, and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer-term commodity forwards, futures, and swaps.

Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities is presented below:

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2023:							
Electricity physical forwards	$ 14	$ 43	Discounted cash flow	Electricity forward price (per MWh)	$ 37.53	$ 153.33	$ 84.58
Natural gas financial swaps		16	Discounted cash flow	Natural gas forward price (per Dth)	2.25	8.89	3.37
Electricity financial futures			Discounted cash flow	Electricity forward price (per MWh)	65.3	107.31	91.33
	$ 14	$ 59					
As of December 31, 2022:							
Electricity physical forwards	$ 52	$ 93	Discounted cash flow	Electricity forward price (per MWh)	$ 35.00	$ 270.00	$ 101.27
Natural gas financial swaps	6	8	Discounted cash flow	Natural gas forward price (per Dth)	2.71	24.71	4.42
Electricity financial futures	11		Discounted cash flow	Electricity forward price (per MWh)	54.17	143.70	104.21
	$ 69	$ 101					

The significant unobservable inputs used in the Company's fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter-term contracts, PGE employs the mid-point of the bid-ask spread of the market and these inputs are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These price inputs are validated against independent market data from multiple sources. For certain long-term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such instances, the Company uses internally-developed price curves, which derive longer-term prices and utilize observable data when available. When not available, regression techniques are used to estimate unobservable future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a quarterly basis by the Company.

The Company's Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and the Company's position as either the buyer or seller of the contract. Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Input	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Changes in the fair value of net liabilities from price risk management activities (net of assets from price risk management activities) classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31, 2023	2022
Net liabilities from price risk management activities as of beginning of year	$ 32	$ 85
Net realized and unrealized losses/(gains) *	26	(84)
Net transfers from Level 3 to Level 2	(13)	31
Net liabilities from price risk management activities as of end of year	$ 45	$ 32
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ 17	$ (82)

* Includes $9 million in net realized losses in 2023 and $2 million in net realized gains in 2022.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers into and out of Level 3 at the end of the reporting period for all of its derivative instruments.

During the years ended December 31, 2023 and 2022, there were no transfers into Level 3 from Level 2. Transfers from Level 3 are reflected in the table above.

Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's Comparative Balance Sheet. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2023, the carrying amount of PGE's long-term debt was $3,999 million and its estimated aggregate fair value was $3,705 million. As of December 31, 2022, the carrying amount of PGE's long-term debt was $3,659 million with an estimated aggregate fair value of $2,984 million.

For fair value information concerning the Company's pension plan assets, see Note 10, Employee Benefits.

NOTE 5: RISK MANAGEMENT

Price Risk Management

PGE participates in the wholesale marketplace to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of, and secure reasonably priced power for, its retail customers, manage risk, and administer the Company's long-term wholesale contracts. Wholesale market transactions include purchases and sales of both power and fuel resulting from economic dispatch decisions with respect to Company-owned generating resources. The Company also performs portfolio management and wholesale market sales services for third parties in the region. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, from which changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flows.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the Comparative Balance Sheet, may include forward, future, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the Statement of Income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not intend to engage in trading activities for non-retail purposes.

PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2023	2022
Current assets:		
Commodity contracts:		
Electricity	$ 13	$ 112
Natural gas	9	201
Total current derivative assets	22	313
Noncurrent assets:		
Commodity contracts:		
Electricity	9	44
Natural gas	2	30
Total noncurrent derivative assets	11	74
Total derivative assets	$ 33	$ 387
Current liabilities:		
Commodity contracts:		
Electricity	$ 51	$ 93
Natural gas	113	25
Total current derivative liabilities	164	118
Noncurrent liabilities:		
Commodity contracts:		
Electricity	22	53
Natural gas	53	22
Total noncurrent derivative liabilities	75	75
Total derivative liabilities	$ 239	$ 193

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2035, were as follows (in millions):

	As of December 31,			
	2023		2022	
Commodity contracts:				
Electricity	3	MWh	6	MWh
Natural gas	213	Dth	211	Dth
Foreign currency contracts	$ 20	Canadian	$ 10	Canadian

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement at gross values on the Comparative Balance Sheet. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2023, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $28 million, for which PGE has posted $1 million collateral. Of the gross amounts recognized as of December 31, 2023, $3 million was for electricity and $25 million was for natural gas. As of December 31, 2022, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $5 million, entirely for natural gas, for which PGE has posted no collateral.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased Power in the Statement of Income and were as follows (in millions):

	Years Ended December 31,	
	2023	2022
Commodity contracts:		
Electricity	$ (130)	$ (187)
Natural Gas	357	(388)
Foreign currency contracts	(1)	1

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net losses of $403 million and net gains of $188 million for the years ended December 31, 2023 and 2022, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2023 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2024	2025	2026	2027	2028	Thereafter	Total
Commodity contracts:							
Electricity	$ 39	$ 18	$ (2)	$ (2)	$ (1)	$ (1)	$ 51
Natural gas	104	36	14	1			155
Net unrealized (gain)/loss	$ 143	$ 54	$ 12	$ (1)	$ (1)	$ (1)	$ 206

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and S&P Global Ratings (S&P). Should Moody's and/or S&P reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties. Certain other counterparties would have the right to terminate their agreements with the Company.

The aggregate fair value of derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2023 was $217 million, for which the Company has posted $95 million in collateral, consisting of $40 million of letters of credit and $55 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2023, the cash requirement to either post as collateral or settle the instruments immediately would have been $166 million. As of December 31, 2023, PGE had $26 million cash collateral posted for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Special Deposits included in Other current assets on the Company's Comparative Balance Sheet.

As of December 31, 2023, PGE received from counterparties $17 million in collateral, consisting of $12 million of letters of credit and $5 million of cash. The obligation to return cash collateral held for derivative instruments is included in Accrued expenses and other current liabilities on the Company's Comparative Balance Sheet.

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. Credit risk may be concentrated to the extent PGE's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. The Company manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. PGE also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded as needed to reflect credit risk related to wholesale accounts receivable.

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 4, Fair Value of Financial Instruments.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

Regulatory assets and liabilities consist of the following (dollars in millions):

	Remaining Amortization Period	As of December 31, 2023	2022
Regulatory assets:			
Price risk management	(1)	$ 206	$ 2
Pension and other postretirement plans	(2)	104	95
Deferred income taxes	(7)	56	55
February 2021 ice storm and damage	(3)	69	78
Power cost adjustment mechanism	(4)	16	29
2020 Labor Day wildfire	(3)	29	32
COVID-19	(5)	14	22
Wildfire mitigation	(6)	30	29
Other	Various	90	92
Total regulatory assets		$ 614	$ 434
Regulatory liabilities:			
Deferred income taxes	(8)	233	249
Price risk management	(1)		195
Other	Various	53	68
Total regulatory liabilities		$ 286	$ 512

(1)No amortization period in accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains on derivative instruments until settlement.
(2)Recovery expected over the average service life of employees.
(3)Amortization will occur over a 7-year period starting January 1, 2023.
(4)Amortization will occur over a 2-year period starting January 1, 2023.
(5)Amortization will occur over a 2-year period starting April 1, 2023.
(6)Amounts deferred between January 1, 2022 and May 8, 2022 will amortize over a 2-year period beginning October 20, 2023. Amounts deferred between May 9, 2022 and December 31, 2022 will amortize over a 1-year period beginning October 20, 2023. Amounts deferred between January 1, 2023 and December 31, 2023 have not yet been approved for amortization.
(7)Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(8)Refund expected as the balance is reversed using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 5, Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic pension and postretirement benefit costs. For further information, see Note 10, Employee Benefits.

Debt issuance costs represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

Trojan decommissioning activities represents the deferral of ongoing costs and adjustments to the Trojan ARO associated with monitoring spent nuclear fuel at Trojan, net of amortization of customer collections. In addition, proceeds received from the United States Department of Energy (USDOE) for the reimbursement of costs to monitor the ISFSI is deferred and offsets customer collections.

February 2021 ice storm and damage represents the costs incurred to repair damage to PGE's transmission and distribution systems and restore power to customers as a result of the historic storms that ultimately led Oregon's Governor to declare a state of emergency in February 2021.

*Power Cost Adjustment Mechanism*For the year ended December 31, 2021, actual NVPC was $62 million above baseline NVPC, and therefore PGE deferred $29 million, which represents 90% of the excess variance expected to be collected from customers for the year ended December 31, 2021.

2020 Labor Day wildfire represents incurred costs to replace and rebuild PGE facilities damaged by the fires, as well as address fire-damaged vegetation and other resulting debris and hazards both in and outside of PGE's property and right-of-way.

*COVID-19*In March 2020, PGE filed an application with the OPUC for deferral of lost revenue and certain incremental costs, such as bad debt expense, related to COVID-19. PGE's deferral application was approved by the OPUC in October 2020 with final stipulations for the Term Sheet approved in November 2020.

As of December 31, 2023 and December 31, 2022, PGE's deferred balance was $14 million and $22 million, respectively, comprised primarily of bad debt expense in excess of what was collected in customer prices. PGE filed a request for amortization of deferred amounts on December 16, 2022, which reflected a $12 million adjustment primarily related to bad debt write-offs being lower than estimated. During the March 14, 2023 public meeting, Staff recommended the OPUC approve PGE's filing of advice No. 22-45 associated with the recovery of the COVID-19 deferral. On March 21, 2023 Advice No. 22-45 was approved by the OPUC, allowing for amortization of deferred amounts over a two-year period beginning April 1, 2023.

Wildfire mitigation represents incremental costs and investments made by PGE related to intensifying efforts on its system to mitigate the risk of wildfire and improve resiliency to wildfire damage under SB 762, enacted in July 2021. These efforts include enhanced tree and brush clearing, hardening equipment, and making emergency plans in close partnership with local, state, and federal land and emergency management agencies to further expand the use of a public safety power shutoff, if the need should arise. Pursuant to SB 762, PGE submitted its 2023 risk-based Wildfire Mitigation Plan to the OPUC in December 2022 and it was approved in Order 23-221 on June 26, 2023.

As of December 31, 2023 and December 31, 2022, PGE's deferred balance related to wildfire mitigation was $29 million and $28 million, respectively. The 2023 balance is comprised of:

Base Rates - The outcome of PGE's 2022 General Rate Case (GRC) provided an annual amount of $24 million to be collected in base rates in regard to wildfire mitigation efforts beginning May 9, 2022. As of December 31, 2023, there was $1 million in the balancing account.

Previously Deferred - Prior to establishing the base rates collection noted above, PGE had deferred incremental costs related to wildfire mitigation and as of December 31, 2023 this balance is $28 million. On July 1, 2022, PGE filed an application for reauthorization of OPUC Docket UM 2019 to defer incremental wildfire mitigation costs that exceed the amount granted in base rates. On May 10, 2023, in Order No. 23-173, the OPUC approved an automatic adjustment clause mechanism to recover wildfire mitigation costs (capital and expense). PGE and certain parties agreed to a stipulation, which was adopted by the OPUC on October 18, 2023, that allows PGE to begin amortizing $27 million comprised of $23 million related to the September 30, 2023 deferred operating expense balance of $31 million and $4 million for capital related revenue requirement.

Beginning January 1, 2024, and in conjunction with the Company's current GRC proceeding, PGE will remove collections related to wildfire mitigation costs (for both capital and operating expense) from base prices and include the forecasted costs within the automatic adjustment clause in a separate tariff. Differences between actual and forecasted costs will be recorded as regulatory assets or liabilities within the automatic adjustment clause balancing account, which will not be subject to an earnings test.

*Boardman Refund*In 2020, intervenors filed a deferral application with the OPUC that would have required PGE to defer and refund the revenue requirement associated with the Company's Boardman coal-fired generating plant (Boardman) then included in customer prices as established in the Company's 2019 GRC. Customer prices resulting from the 2022 GRC Order no longer included any revenue requirement related to Boardman after new customer prices took effect on May 9, 2022. The OPUC found that the deferral was warranted with amortization subject to an earnings test.

Subsequently, PGE and parties submitted stipulations to the OPUC reflecting agreements that resolved all matters related to this deferral and stated that PGE would refund $6.5 million to customers. On June 5, 2023, the OPUC issued Order 23-195, which approved the stipulations. The refund amount, plus interest, is being amortized into customer prices over a two-year period that began July 1, 2023.

Deferred income taxes represents income tax benefits primarily from property-related timing differences that will be refunded to customers when the temporary differences reverse. Substantially all of the amounts deferred are subject to tax normalization rules that require that the impact to the results of operations of reversing the excess deferred income tax balance cannot occur more rapidly than over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes.

Asset retirement obligations represents the difference in the timing of recognition of: i) the amounts recognized for Depreciation Expense of the asset retirement costs and Accretion Expense of the ARO; and ii) the amount recovered in customer prices.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31, 2023	2022
Trojan decommissioning activities	$ 174	$ 170
Utility plant	85	86
Non-utility property	27	33
Total asset retirement obligations	286	289

Trojan decommissioning activities represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI will store the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2059. In 2023, the Company recorded an increase in the ARO of $9 million due to an increase in expected annual ISFSI operation costs. The Company also recorded Accretion Expense of $7 million and a reduction of $12 million due to settled liabilities.

Under a settlement agreement reached with the USDOE, the Company receives annual reimbursement from the USDOE for certain costs related to monitoring the ISFSI. Pursuant to this process, the USDOE reimbursed the co-owners $9 million in 2023 for costs incurred in 2022 and $6 million in 2022 for costs incurred in 2021 resulting from USDOE delays in accepting spent nuclear fuel.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, and distribution and transmission assets, the disposal of which is legally required. During 2023, utility AROs decreased by $1 million, with the change comprised of new liabilities incurred of $2 million, Accretion Expense of $4 million, and a reduction of $7 million due to settled liabilities.

Non-utility property primarily represents AROs that have been recognized for portions of unregulated properties that are currently or previously leased to third parties. Revisions to estimates for non-utility AROs relate to assets that are no longer in service and the offset is charged directly to Miscellaneous Nonoperating Income (Acct 421) on the Statement of Income in the period in which the revisions are probable and reasonably estimable. Non-utility AROs are not subject to regulatory deferral.

The following is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31,		
	2023	2022	2021
Balance as of beginning of year	$ 289	$ 269	$ 291
Liabilities incurred	2	1	
Liabilities settled	(25)	(27)	(18)
Accretion Expense	11	10	10
Revisions in estimated cash flows	9	36	(14)
Balance as of end of year	$ 286	$ 289	$ 269

Pursuant to regulation, the amortization of Utility Plant AROs is included in Depreciation Expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices with an equal amount recorded in Total Utility Operating Expenses.

PGE maintains a separate Nuclear decommissioning trust in the Comparative Balance Sheet for funds collected from customers through prices to cover the cost of Trojan decommissioning activities.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to Accumulated Provision for Depreciation, Amortization, and Depletion, which is included in Regulatory liabilities on PGE's Comparative Balance Sheet.

NOTE 8: CREDIT FACILITIES

On August 18, 2023, PGE entered into an amendment of its existing revolving credit facility. As of December 31, 2023, PGE had a $750 million revolving credit facility scheduled to expire in September 2028. The Company has the ability to expand the revolving credit facility to $850 million, if needed. Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, including as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on the Company's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2023, PGE was in compliance with this covenant with a 56.2% debt to total capital ratio. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. The Company believes these potential adjustments will have an immaterial impact on PGE's results of operations.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2023, PGE had $146 million commercial paper outstanding.

Under the revolving credit facility, as of December 31, 2023, PGE had no borrowings outstanding and there were no letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $750 million, however, as PGE has elected to limit it's borrowings to cover any potential need to repay outstanding commercial paper, the elected available credit capacity is $604 million.

PGE typically classifies borrowings under the revolving credit facility and outstanding commercial paper as Notes Payable in the Comparative Balance Sheet.

In addition, PGE has four letter of credit facilities that provide a total capacity of $320 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, a total of $106 million of letters of credit were outstanding as of December 31, 2023. Outstanding letters of credit are not reflected on the Company's Comparative Balance Sheet.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount up to $900 million through February 6, 2026.

Short-term borrowings under these credit facilities, and related interest rates, are reflected in the following table (dollars in millions).

	Year Ended December 31,	
	2023	2022
Average daily amount of short-term debt outstanding	$ 63	$ 2
Weighted daily average interest rate *	5.5 %	3.4 %
Maximum amount outstanding during the year	$ 225	$ 135

* Excludes the effect of commitment fees, facility fees, and other financing fees.

NOTE 9: LONG-TERM DEBT & OTHER FINANCING ARRANGEMENTS

Long-term debt

Long-term debt consists of the following (in millions):

	As of December 31,	
	2023	2022
First Mortgage Bonds, rates range from 1.82% to 6.88%, with a weighted average rate of 4.32% in 2023 and 4.09% in 2022, due at various dates through 2059.	$ 3,880	$ 3,280
Unsecured term bank loans, variable rate of approximately 5.30% at December 31, 2022		260
Pollution Control Revenue Bonds, rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	3,999	3,659
Less: Unamortized debt expense	(14)	(13)
Less: Current portion of long-term debt	(80)	(260)
Long-term debt, net of current portion	$ 3,905	$ 3,386

*First Mortgage Bonds*On August 29, 2023, PGE entered into a Bond Purchase Agreement related to the sale of $500 million in First Mortgage Bonds (FMBs), the bonds consist of:

a series, due in 2030, in the amount of $50 million that bear interest at an annual rate of 5.44%;

a series, due in 2033, in the amount of $150 million that bear interest at an annual rate of 5.48%;

a series, due in 2038, in the amount of $100 million that bear interest at an annual rate of 5.68%;

a series due in 2053, in the amount of $100 million that bear interest at an annual rate of 5.78%; and

a series due in 2059, in the amount of $100 million that bear interest at an annual rate of 5.83%.

As of December 31, 2023, all series, totaling $500 million, were issued and funded in full.

On November 30, 2022, PGE entered into a Bond Purchase Agreement related to the sale of $200 million in First Mortgage Bonds (FMBs), the first half of which funded in 2022 and the remaining $100 million funded in full on January 13, 2023.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs.

*Term Loan*On October 21, 2022, PGE obtained a 366-day term loan from lenders in the aggregate principal of $260 million under a 366-Day Bridge Credit Agreement. The term loan bore interest for the relevant interest period at the Term Secured Overnight Financing Rate (SOFR) plus Term SOFR Adjustment Rate of 10 basis points and Applicable Margin of 87.5 basis points. The interest rate was subject to adjustment pursuant to the terms of the loan. On March 1, 2023, this term loan was repaid in full.

*Pollution Control Revenue Bonds*On March 11, 2020, PGE completed the remarketing of an aggregate principal amount of $119 million of Pollution Control Revenue Refunding Bonds (PCRBs), which consist of $98 million aggregate principal of PCRBs that bear an interest rate of 2.125%, and $21 million aggregate principal of PCRBs that bear an interest rate of 2.375%, both due in 2033. At the time of remarketing, the Company chose a new interest rate period that was fixed term. The new interest rate was based on market conditions at the time of remarketing. The PCRBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on the PCRBs.

As of December 31, 2023, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2024	$ 80
2025	
2026	
2027	160
2028	100
Thereafter	3,659
	$ 3,999

Pelton/Round Butte financing arrangement

Under terms of an agreement (the "Agreement") approved by the OPUC in 2000, PGE had a 66.67% ownership interest in the 455 Megawatt (MW) Pelton/Round Butte hydroelectric project on the Deschutes River (Pelton/Round Butte), with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). In the Agreement, the CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte which was exercised in 2022. Under terms of the Agreement, the CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, the CTWS' ownership percentage would exceed 50%. PGE remains the operator of the project.

PGE has agreed to purchase 100% of the CTWS' share of the project's output under a Power Purchase Agreement (PPA) through 2040. The exercise of the purchase option on January 1, 2022 was evaluated as a sale-leaseback arrangement, and PGE determined that the transaction did not qualify for sale-leaseback accounting. As a result, the transaction is accounted for as a financing arrangement. PGE will continue to record the tangible utility asset within Net Utility Plant on the Comparative Balance Sheet as if it were the legal owner and will continue to recognize Depreciation Expensedepreciation expense over the estimated useful life. The monthly PPA payments are split between Interest Charges and a reduction of the principal portion of the financing obligation, which is included in Other noncurrent liabilities. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

As of December 31, 2023, the future minimum payments on the financing arrangement are as follows (in millions):

Years ending December 31:	
2024	$ 2
2025	5
2026	5
2027	5
2028	5
Thereafter	64
Total Payments	86
Less: Imputed Interest	(57)
Present value of minimum payments	$ 29

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

*Defined Benefit Pension Plan*PGE sponsors a non-contributory defined benefit pension plan, which is closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions that are reviewed annually and updated as appropriate.

PGE made no contributions to the pension plan in 2023, 2022, and 2021. PGE expects to contribute $26 million to the pension plan in 2024.

*Other Postretirement Benefits*PGE offers non-contributory postretirement health and life insurance plans, and provides health reimbursement arrangements (HRAs) to its employees (collectively, "Other Postretirement Benefits" in the following tables). PGE's obligation pursuant to the postretirement health plan is limited by establishing a maximum benefit per employee with any additional cost the responsibility of the employee.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, equity securities, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions that are reviewed annually by PGE and updated as appropriate, with measurement dates of December 31.

In 2023, PGE executed a sale of the retiree portion of the Nonrepresented Life Insurance Plan as well as a settlement of the active non-union portion of the Nonrepresented HRA Plan, resulting in a combined $1.4 million settlement gain, which have been recorded in Miscellaneous income (expense), net on the Statement of Income.

*Non-Qualified Benefit Plan*The NQBP in the following tables include obligations for a Supplemental Executive Retirement Plan and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also includes pension make-up benefits for employees that participate in the Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide partial funding for the future requirements of these plans. The assets of such trust are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bonds, and equity mutual funds, are classified as equity or trading debt securities and recorded at fair value. The measurement date for the NQBP is December 31. For further information regarding these trust investments, see Note 4, Fair Value of Financial Instruments.

*Other NQBP*In addition to the NQBP discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. PGE holds investments in a NQBP trust that are intended to be a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included Other Special Funds in PGE's Comparative Balance Sheet are as follows as of December 31 (in millions):

	2023			2022		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	$ 17	$ 18	$ 35	$ 19	$ 19	$ 38
Non-qualified benefit plan liabilities	18	63	81	18	67	85

*Investment Policy and Asset Allocation*The Finance Committee of the PGE Board of Directors appoints an Investment Committee, which is comprised of certain members of management from the Company, and establishes the Company's asset allocation. The Investment Committee is then responsible for the implementation of the asset allocation and oversight of the benefit plan investments. The Company's investment strategy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities, and other alternative investments. Asset classes are regularly rebalanced to ensure asset allocations remain within prescribed parameters.

The asset allocations for the plans, and the target allocation, are as follows:

	As of December 31,			
	2023		2022	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Growth securities	53 %	55 %	55 %	55 %
Liability Hedging Fixed Income securities	47	45	45	45
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	41 %	39 %	39 %	40 %
Debt securities	59	61	61	60
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	1 %	4 %	7 %	5 %
Debt securities	13	10	9	11
Insurance contracts	86	86	84	84
Total	100 %	100 %	100 %	100 %

* The target for the Defined Benefit Pension Plan represents the mid-point of the investment target range. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the NQBP, these targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average targets for the Other Postretirement Benefit Plans and NQBP, reported percentages are affected by the fair market values of the investments within the pools.

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets by asset category are as follows (in millions):

	Level 1	Level 2	Level 3	Other *	Total
As of December 31, 2023:					
Defined Benefit Pension Plan assets:					
Equity securitiesDomestic	$ 14	$	$	$	$ 14
Investments measured at NAV:					
Money market funds				30	30
Collective trust funds				484	484
Private equity funds				2	2
	$ 14	$	$	$ 516	$ 530
Other Postretirement Benefit Plans					

assets:					
Money market funds	$ 3	$	$	$	$ 3
Equity securities:					
Domestic		2			2
International	4				4
Debt securitiesDomestic		4			4
Investments measured at NAV:					
Money market funds				6	6
Collective trust funds				4	4
	$ 7	$ 6	$	$ 10	$ 23
As of December 31, 2022:					
Defined Benefit Pension Plan assets:					
Equity securitiesDomestic	$ 16	$	$	$	$ 16
Investments measured at NAV:					
Money market funds				4	4
Collective trust funds				525	525
Private equity funds				2	2
	$ 16	$	$	$ 531	$ 547
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$	$	$	$ 4
Equity securities:					
Domestic		2			2
International	3				3
Debt securitiesDomestic government		4			4
Investments measured at NAV:					
Money market funds				5	5
Collective trust funds				3	3
	$ 7	$ 6	$	$ 8	$ 21

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following discussion provides information regarding the methods used in valuation of the various asset class investments held in the pension and other postretirement benefit plan trusts.

*Money market funds*PGE invests in money market funds that seek to maintain a stable NAV. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, or certificates of deposit. Some of the money market funds held in the trusts are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market. The remaining money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

*Equity securities*Equity mutual fund and common stock securities are classified as Level 1 securities as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Mutual fund assets included in separately managed accounts are classified as Level 2 securities due to pricing inputs that are directly or indirectly observable in the marketplace.

*Debt Securities*Debt security investment funds are classified as Level 2 securities as pricing for underlying securities are determined by evaluating pricing data, such as broker quotes for similar securities, adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, if applicable.

*Collective trust funds*Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset back securities assets, are included in commingled trusts or separately managed accounts. The funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

*Private equity funds*PGE invests in a combination of primary and secondary fund-of-funds, which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, partnerships, joint ventures, venture capital, buyout, and special situations. Private equity investments are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and NQBP as of and for the years ended December 31, 2023 and 2022. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2023	2022	2023	2022	2023	2022
Benefit obligation:						
As of January 1	$ 695	$ 972	$ 43	$ 71	$ 18	$ 27
Service cost	10	17	1	1		
Interest cost	37	28	2	2	1	1
Actuarial gain	37	(255)	3	(15)	2	(7)
Benefits paid from plan assets	(86)	(69)	(2)	(4)	(3)	(3)
Benefits paid from Company assets			(1)			
Administrative expenses	(3)	(3)				
Plan amendment		5		1		
Plan settlements			(11)	(13)		
As of December 31	$ 690	$ 695	$ 35	$ 43	$ 18	$ 18
Fair value of plan assets:						
As of January 1	$ 547	$ 800	$ 21	$ 37	$ 19	$ 21
Actual return on plan assets	72	(181)	2	(6)	(2)	(2)
Company contributions			13	7	3	3
Benefit payments	(86)	(69)	(2)	(4)	(3)	(3)
Administrative expenses	(3)	(3)				
Plan settlements			(11)	(13)		
As of December 31	$ 530	$ 547	$ 23	$ 21	$ 17	$ 19
Unfunded position as of December 31	$ (160)	$ (148)	$ (12)	$ (22)	$ (1)	$ 1
Accumulated benefit plan obligation as of December 31	$ 645	$ 656	N/A	N/A	$ 17	$ 17
Classification in Comparative Balance Sheet:						
Noncurrent asset	$	$	$	$	$ 17	$ 19
Current liability				(1)	(2)	(2)
Noncurrent liability	(160)	(148)	(12)	(21)	(16)	(16)
Net asset (liability)	$ (160)	$ (148)	$ (12)	$ (22)	$ (1)	$ 1
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 8	$ (28)	$ 2	$ (8)	$ 2	$ (7)

Net settlement gain (loss)			1	11		
Net prior service credit		5				
Amortization of net actuarial gain (loss)		(15)	1		(1)	(1)
Amortization of prior service credit	1	2				
	$ 9	$ (36)	$ 4	$ 3	$ 1	$ (8)
Amounts included in AOCL: *						
Net actuarial loss (gain)	$ 105	$ 96	$ (3)	$ (7)	$ 7	$ 6
Prior service cost	(1)	(1)				
	$ 104	$ 95	$ (3)	$ (7)	$ 7	$ 6

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are classified as Other Regulatory Assets or Other Regulatory Liabilities, respectively, as future recoverability is expected from retail customers.

Significant actuarial gains (losses) experienced that resulted in changes in projected benefit obligation included the following:

For the defined benefit pension plan, actuarial gains and losses due to demographic experience, including assumption changes, were a loss of $37 million and a gain of $255 million, and the changes between actual and expected return on plan assets were a gain of $29 million and a loss of $227 million, for the years ended December 31, 2023 and 2022, respectively.

For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were a loss of $3 million and a gain of $15 million, and the changes between actual and expected return on plan assets were a gain of $1 million and a loss of $6 million, for the years ended December 31, 2023 and 2022, respectively.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2023	2022	2023	2022	2023	2022
Service cost	$ 10	$ 17	$ 1	$ 1	$	$
Interest cost on benefit obligation	37	28	2	2	1	1
Expected return on plan assets	(43)	(46)	(1)	(2)		
Amortization of prior service credit	(1)	(2)				
Amortization of net actuarial loss		15	(1)		1	1
Settlement gain			(1)	(11)		
Net periodic benefit cost	$ 3	$ 12	$	$ (10)	$ 2	$ 2

The following assumptions were used in determining benefit obligations and net period benefit costs:

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2023	2022	2023	2022	2023	2022
Assumptions used to determine benefit obligations:						
Discount rate	5.13 %	5.42 %	5.18 % 5.57 %	5.47% - 5.51 %	5.13 %	5.42 %
Rate of compensation increase	4.19 %	4.21 %	4.06 %	4.04 %	4.01 %	5.10 %
Assumptions used to determine net periodic benefit cost:						
Discount rate	5.42 %	2.92 %	5.47 % 6.06 %	2.75% - 3.11 %	5.42 %	2.92 %
Rate of compensation increase	4.21 %	4.26 %	4.04 %	4.13 %	5.10 %	4.10 %
Long-term rate of return on plan assets	6.75 %	6.75 %	4.77 %	4.83 %	N/A	N/A

As of December 31, 2023, there are no liabilities with sensitivity to health care cost trend rates.

The expected rate of return on plan assets each year is based on the approved asset allocation. A forward looking building blocks approach is used with historical returns, capital markets information and survey information used to support the expected rate of return on plan assets assumption.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.50% reduction in the expected long-term rate of return on plan assets, or a 0.50% reduction in the discount rate, would have the effect of increasing the 2023 net periodic pension expense by approximately $3 million and $1 million, respectively.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2024	2025	2026	2027	2028	2029 - 2033
Defined benefit pension plan	$ 76	$ 49	$ 49	$ 49	$ 49	$ 241
Other postretirement benefits	4	4	4	5	2	10
Non-qualified benefit plans	2	2	2	2	2	9
Total	$ 82	$ 55	$ 55	$ 56	$ 53	$ 260

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE's defined benefit pension plan, the Company matches employee contributions to the 401(k) Plan up to 6% of the employee's base pay. For eligible employees who are not covered by PGE's defined benefit pension plan, the Company contributes 5% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan, and also matches employee contributions up to 5% of the employee's base pay.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company contributes an additional 1% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $31 million in 2023, $29 million in 2022, and $26 million in 2021.

NOTE 11: INCOME TAXES

Income tax expense/(benefit) consists of the following (in millions):

	Years Ended December 31,	
	2023	2022
Current:		
Federal	$ 11	$ 9
State and local	26	24
	37	33
Deferred:		
Federal	4	(1)
State and local	4	7
	8	6

Income tax expense	$ 45	$ 39

The significant differences between the U.S. Federal statutory rate and PGE's Effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,	
	2023	2022
Federal statutory tax rate	21.0 %	21.0 %
Federal tax credits (1)	(9.5)	(12.8)
State and local taxes, net of federal tax benefit	8.6	8.8
Flow through depreciation and cost basis differences	(0.4)	0.8
Reversal of excess deferred income tax (2)	(3.9)	(4.5)
Other	0.6	1.0
Effective tax rate	16.4 %	14.3 %

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation will end at various dates through 2030. Federal tax credits also includes all other federal tax credits and related deferrals. The tax credit deferrals are established to provide the benefit back to customers over a period agreed upon with the OPUC.

(2) The majority of excess deferred income taxes related to remeasurement under the Tax Cuts and Jobs Act is subject to Internal Revenue Service (IRS) normalization rules and will be reversed over the remaining regulatory life of the assets using the average rate assumption method.

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31,	
	2023	2022
Deferred Income Tax Assets:		
Employee benefits	$ 99	$ 99
Depreciation and amortization	309	307
Regulatory liabilities	21	76
Tax credits	73	102
Price risk management	66	54
Other	2	3
Total Deferred Income Tax Assets	570	641
Deferred Income Tax Liabilities:		
Depreciation and amortization	888	857
Price risk management	9	107
Regulatory assets	146	101
Other	16	16
Total Deferred Income Tax Liabilities	1,059	1,081
Accumulated Deferred Income Tax Liability, net	$ 489	$ 440

As of December 31, 2023, PGE has federal credit carryforwards of $73 million, consisting of primarily PTCs, which will expire at various dates through 2043. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2023 and 2022 will be realized; accordingly, no material valuation allowance has been recorded. As of December 31, 2023, and 2022, PGE had no material unrecognized tax benefits.

PGE and its subsidiaries file a federal income tax return. The Company also files income tax returns in the states of Oregon, California, and Montana, and in certain local jurisdictions. The Company files in other states to maintain compliance with remote worker rules and regulations. These additional state filings are not significant to the financial statements. The IRS has completed its examination of all tax years through 2010 and all issues were resolved related to those years. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

NOTE 12: EQUITY-BASED PLANS

At the Market Offering Program

On April 28, 2023, PGE entered into an equity distribution agreement under which it could sell up to $300 million of its common stock through at the market offering programs. As of December 31, 2023, pursuant to the terms of the equity distribution agreement, PGE entered into separate forward sale agreements with forward counterparties and under such agreements, the Company could have physically settled by delivering 1,714,971 shares to the counterparties in exchange for cash of $78 million. Any proceeds from the issuances of common stock will be used for general corporate purposes and investments in renewables and non-emitting dispatchable capacity.

Equity Forward Sale Agreement

In 2022, PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 10,100,000 shares of its common stock. In March 2023, the Company issued 7,178,016 shares pursuant to the EFSA and received net proceeds of $300 million. In June 2023, the Company issued 2,212,610 shares pursuant to the EFSA and received net proceeds of $92 million. On July 12, 2023, the Company issued 2,224,374 shares pursuant to the EFSA, settling the equity forward transaction, and received net proceeds of $92 million.

Pursuant to the terms of the EFSA, the forward counterparties borrowed 11,615,000 shares of PGE's common stock, including 1,515,000 shares in connection with the underwriters' exercise of their option to purchase additional shares, from third parties in the open market and sold the shares to a group of underwriters for $43.00 per share, less an underwriting discount equal to $1.23625 per share. PGE will not receive any proceeds from the sale of common stock until the EFSA is settled (described above), and at that time PGE will record the proceeds, if any, in equity.

PGE concluded that the EFSA was an equity instrument and that it qualified for an exception from derivative accounting because the EFSA was indexed to its own stock.

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock or 1,500 shares (based on fair value on the purchase date), whichever is less. Two six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2023, there were 119,546 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

PGE has a Dividend Reinvestment and Direct Stock Purchase Plan (DRIP), under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2023, there were 2,456,710 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company Stock Incentive Plan as amended and restated effective February 13, 2018 (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units (RSUs) with time-based vesting conditions (time-based RSUs) and performance-based vesting conditions (performance-based RSUs), to non-employee directors, officers, or certain key employees. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Nonvested units as of December 31, 2021	574,810	48.07
Granted	271,696	51.29
Forfeited	(76,913)	49.48
Vested	(190,132)	49.11
Nonvested units as of December 31, 2022	579,461	49.23
Granted	421,788	47.82
Forfeited	(57,566)	48.03
Vested	(297,986)	52.45
Nonvested units as of December 31, 2023	645,697	47.57

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 1,732,922 shares remain available for future issuance as of December 31, 2023.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. Each DER represents an amount equal to dividends paid to stockholders on a share of PGE's common stock and vests on the same schedule as the related RSU. The DERs are settled in shares of PGE common stock valued either at the closing stock price on the vesting date (for performance-based RSUs) or dividend payment date (for all other grants).

Time-based RSUs generally vest over a period of up to three years from the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was $9 million for the year ended December 31, 2023 and $5 million for 2022.

Performance-based RSUs vest based on the extent to which performance goals are met at the end of a three-year performance period, subject to adjustment by the Compensation, Culture and Talent Committee of PGE's Board of Directors. The number of RSUs that may vest under the grants is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) average megawatts of forecast energy from clean or certain low-carbon emitting resources added to PGE's energy supply portfolioand relative total stockholder return (TSR) as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 200% of the RSUs granted.

For return on equity, average EPS growth and carbon reduction metrics of the performance-based RSUs, fair value is measured based on the NYSE closing price of PGE common stock on the date of grant. For the TSR portion of the performance-based RSUs, fair value is determined using a Monte Carlo simulation with the following weighted average assumptions:

	2023	2022
Risk-free interest rate	4.2 %	1.7 %
Expected term (in years)	2.9	2.9
Volatility	21.8 % - 31.5 %	26.4 % - 37.9 %

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 129.7%, 114.9%, and 105.1% of awarded performance-based RSUs for the respective 2023, 2022, and 2021 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $7 million for the year ended December 31, 2023 and $6 million for 2022.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $17 million for the year ended December 31, 2023 and $15 million for 2022. Such amounts differ from those reported in Other Paid-in Capital for stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and General Expenses in the Statement of Income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to Stockholder equity of $4 million in 2023 and in 2022.

As of December 31, 2023, unrecognized stock-based compensation expense was $18 million, which is expected to be recognized over a weighted average period of one to three years. No stock-based compensation costs have been capitalized.

NOTE 14: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2023, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2024	2025	2026	2027	2028	Thereafter	Total
Capital and other purchase commitments	$ 694	$ 272	$ 13	$ 5	$ 2	$ 41	$ 1,027
Purchased Power:							
Electricity purchases	727	692	333	294	286	2,766	5,098
Capacity contracts	119	122	96	5	5	64	411
Public utility districts	12	11	10	9	7	16	65
Natural gas	104	69	37	37	37	187	471
Coal and transportation	27	27					54
Total	$ 1,683	$ 1,193	$ 489	$ 350	$ 337	$ 3,074	$ 7,126

*Capital and other purchase commitments*Certain commitments have been made for 2024 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

*Electricity purchases and Capacity contracts*PGE has power purchase agreements with counterparties, which expire at varying dates through 2053, and power capacity contracts through 2051. Expenses associated with these commitments are recorded in Purchased Power and fuel on the Company's Statement of Income.

*Public utility districts*PGE has long-term power purchase agreements with certain public utility districts (PUDs) in the state of Washington:

Grant County PUD for the Priest Rapids and Wanapum Hydroelectric Projects, and

Douglas County PUD for the Wells Hydroelectric Project.

Under one of the Grant County agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether they are operable or not. Under one of the Douglas County agreement, the Company is required to make monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas County's loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

Selected information regarding these projects is summarized as follows (dollars in millions):

	Capacity Charges and Revenue Bonds as of December 31, 2023	PGE's Average Share as of December 31, 2023		Contract Expiration	Total PGE Contract Costs		
		Output	Capacity (in MW)		2023	2022	2021
Priest Rapids and Wanapum	$ 1,883	8.6 %	163	2052	$ 77	$ 45	$ 26
Wells	347	8.1	16	2028	11	12	13

The agreements for Priest Rapids and Wanapum provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro-rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be responsible for a pro-rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax-exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax-exempt purchasers.

*Natural gas*PGE has contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities.

*Coal*The Company has a coal agreement with take-or-pay provisions related to Colstrip Units 3 and 4 coal-fired generating plant (Colstrip) that expires in December 2025.

Guarantees

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. In connection with the agreement to transfer certain tax credits generated in 2023, PGE provided indemnification against the buyer's losses related to a failure to satisfy the PTC qualification or transferability requirements under the Internal Revenue Code, but not due to the action or legal tax status of the buyer or a change in tax law. As of December 31, 2023, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

NOTE 15: LEASES

PGE determines if an arrangement is a lease at inception and whether the arrangement is classified as an operating or finance lease. At commencement of the lease, PGE records a right-of-use (ROU) asset and lease liability in the Comparative Balance Sheet based on the present value of lease payments over the term of the arrangement. ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent PGE's obligation to make lease payments arising from the lease. If the implicit rate is not readily determinable in the contract, PGE uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Contract terms may include options to extend or terminate the lease, and, when the Company deems it is reasonably certain that PGE will exercise that option, it is included in the ROU asset and lease liability.

Lease expense is recognized on the Statement of Income in the appropriate rent expense account on the basis of actual amounts paid under leasing arrangements. For ratemaking purposes, recovery of cost-of-service is generally based on actual lease payments. Any material differences between lease expense and amounts recovered through customer prices is deferred as a regulatory asset or liability. Leased assets are not included in rate base.

PGE does not record leases with a term of 12-months or less in the Comparative Balance Sheet. Total short-term lease costs as of December 31, 2023 are immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

The Company's leases relate primarily to the use of land, support facilities, gas storage, energy storage equipment, and power purchase agreements that rely on identified plant. Variable payments are generally related to gas storage and power purchase agreements for components dependent upon variable factors, such as energy production and property taxes, and are not included in the determination of the present value of lease payments.

The components of lease cost were as follows (in millions):

	2023	2022
Operating lease cost	$ 4	$ 4

Finance lease cost:		
Amortization of right-of-use assets	$ 14	$ 14
Interest on lease liabilities	15	15
Total finance lease cost	$ 29	$ 29
Variable lease cost	$ 33	$ 31

Supplemental information related to amounts and presentation of leases in the Comparative Balance Sheet is presented below (in millions):

	Comparative Balance Sheet Classification	As of December 31, 2023	2022
Operating Leases:			
Operating lease right-of-use assets	Net Utility Plant	$ 18	$ 22
Current liabilities	Obligations Under Capital Leases - Current	$ 3	$ 4
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	16	18
Total operating lease liabilities *		$ 19	$ 22
Finance Leases:			
Finance lease right-of-use assets	Net Utility Plant	$ 291	$ 305
Current liabilities	Obligations Under Capital Leases - Current	$ 20	$ 20
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	289	294
Total finance lease liabilities *		$ 309	$ 314

* Included in lease liabilities are $183 million and $186 million related to power purchase agreements for the years ended December 31, 2023 and 2022, respectively.

Lease term and discount rates were as follows:

	December 31, 2023	December 31, 2022
Weighted Average Remaining Lease Term (in years)		
Operating leases	51	44
Finance leases	21	22
Weighted Average Discount Rate		
Operating leases	4.1 %	3.9 %
Finance leases	4.8 %	4.9 %

PGE's gas storage finance lease contains five 10-year renewal periods which have not been included in the finance lease obligation.

As of December 31, 2023, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2024	$ 3	$ 20
2025	1	27
2026	1	27
2027	1	27
2028	1	26
Thereafter	40	356
Total lease payments	47	483
Less imputed interest	(28)	(174)
Total	$ 19	$ 309

Supplemental cash flow information related to leases for the years indicated was as follows (in millions):

	2023	2022
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 4	$ 4
Operating cash flows from finance leases	15	15
Financing cash flows from finance leases	6	7
Right-of-use assets obtained in leasing arrangements:		
Finance leases		29

*Battery storage agreement*On April 26, 2023, PGE entered into a battery storage purchased power agreement (PPA) that will be accounted for as a lease upon commencement. The lease is expected to commence in December 2024 and has a term of 20 years. The expected total fixed contract consideration will approximate $737 million over the lease term.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2023, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation *	Construction Work In Progress
Colstrip	20.00 %	1986	$ 572	$ 456	$ 1
Pelton/Round Butte	50.01 %	1958 / 1964	216	72	18
Total			$ 788	$ 528	$ 19

* Excludes AROs and Accumulated Provision for Depreciation, Amortization, and Depletion.

Under the respective joint operating agreements for the generating facilities, each participating owner is responsible for financing its share of capital and operating expenses. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the Statement of Income.

The Company operated, and continues to have a 90% ownership interest in Boardman, which ceased coal-fired operations during 2020. Decommissioning of the Boardman facility is substantially complete and as of December 31, 2023, PGE's ARO liability for its 90% share of the decommissioning costs was $6 million.

NOTE 17: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete;

iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor that began in 1997 revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site. PGE has been included among more than one hundred Potentially Responsible Parties (PRPs) as it historically owned or operated property near the river.

A Portland Harbor site remedial investigation was completed pursuant to an agreement between the EPA and several PRPs known as the Lower Willamette Group (LWG), which did not include PGE. The LWG funded the remedial investigation and feasibility study and stated that it had incurred $115 million in investigation-related costs. The Company anticipates that such costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy.

The EPA finalized the feasibility study, along with the remedial investigation, and the results provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued in 2017. The ROD outlined the EPA's selected remediation plan for clean-up of Portland Harbor that had an undiscounted estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs. Remediation construction costs were estimated to be incurred over a 13-year period, with long-term operation and maintenance costs estimated to be incurred over a 30-year period from the start of construction. Stakeholders have raised concerns that EPA's cost estimates are understated, and PGE estimates undiscounted total remediation costs for Portland Harbor per the ROD could range from $1.9 billion to $3.5 billion. The EPA acknowledged the estimated costs are based on data that was outdated and that pre-remedial design sampling was necessary to gather updated baseline data to better refine the remedial design and estimated cost.

A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. With the completion of pre-remedial design sampling, Portland Harbor is now in the remedial design phase, which consists of additional technical information and data collection to be used to design the expected remedial actions. Certain PRPs, not including PGE, have entered into consent agreements to perform remedial design and the EPA has indicated it will take the initial lead to perform remedial design on the remaining areas. The Company anticipates that remedial design costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy. The entirety of Portland Harbor continues under an active engineering design phase.

PGE continues to participate in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including conclusion of remedial design, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor. Based on the above facts and remaining uncertainties in the voluntary allocation process, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that would represent PGE's portion of the liability to clean-up Portland Harbor. However, the Company may obtain sufficient information, prior to the final determination of allocation percentages among PRPs, to develop a reasonable estimate, or range, of its potential liability that would require recording of the estimate, or low end of the range. The Company's liability related to the cost of remediating Portland Harbor could be material to PGE's financial position.

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. The Portland Harbor NRD trustees consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, and the Nez Perce Tribe.

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

The impact of costs related to EPA and NRD liabilities on the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) mechanism. As approved by the OPUC in 2017, the PHERA allows the Company to defer estimated liabilities and recover incurred environmental expenditures related to Portland Harbor through a combination of third-party proceeds, including but not limited to insurance recoveries, and, if necessary, through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent GRC. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or ineligible per the prescribed earnings test. The Company plans to seek recovery of any costs resulting from EPA's determination of liability for Portland Harbor through application of the PHERA. At this time, PGE is not recovering any Portland Harbor cost from the PHERA through customer prices.

Governmental Investigations

In March, April, and May 2021, the Division of Enforcement of the Commodity Futures Trading Commission (the "CFTC"), the Division of Enforcement of the SEC, and the Division of Enforcement of the FERC, respectively, informed the Company they are conducting investigations arising out of the energy trading losses the Company previously announced in August 2020. The Company is cooperating with the CFTC, SEC, and FERC. Management cannot at this time predict the eventual scope or outcome of these matters.

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip, which is located in the state of Montana and operated by one of the co-owners, Talen Montana, LLC (Talen). In May 2022, Talen's parent company, Talen Energy Supply, LLC, filed for chapter 11 bankruptcy protection, although Colstrip continued to operate and generate electricity for PGE customers and others. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. An arbitration process has been initiated to address such business disagreements and has resulted in several legal proceedings. The arbitration along with other matters related to Colstrip, are summarized below.

*Arbitration*In March 2021, co-owner NorthWestern Corporation (NorthWestern) initiated arbitration against all other co-owners of Colstrip to determine whether co-owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or, alternatively, whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. The parties had agreed to stay the arbitration through April 1, 2024, and are now in the process of reengaging in arbitration discussions. An arbitration date has not yet been scheduled. PGE cannot predict the ultimate outcome of the arbitration process.

*Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al*In December 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. In August 2021, the claim was amended to add PGE as a defendant. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court. This case is currently set for trial on November 5, 2024. The Company is unable to predict the outcome or estimate a range of reasonably possible loss in this matter.

*Westmoreland Mine Permits*Two lawsuits were commenced by the Montana Environmental Information Center, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. In the first, the Montana District Court for Rosebud County issued an order vacating a permit (AM4 Permit) for one area (Area B) of the mine. This case was appealed and on November 22, 2023, the Supreme Court of Montana reinstated the Montana District Court vacating the AM4 Permit and affirming the lower court order to return to the Board of Environmental Review for additional permit review considerations. In the second, the Montana Federal District Court issued findings and recommended that a decision approving expansion of the mine into a new area (Area F) should be vacated, but recommending the decision not take effect for 365 days from the date of a final order. On November 24, 2023, the Ninth Circuit Court of Appeals dismissed the appeal by Westmoreland for lack of appellate jurisdiction, and noted that the appropriate venue to raise issues will be the U.S. Office of Surface Mining during the remand process. PGE is not a party to either of these proceedings, but is continuing to monitor the progress of both lawsuits and assess the impact, if any, of the proceedings on Westmoreland's ability to meet its contractual coal supply obligations.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business, which may result in judgments against the Company. Although management currently believes that resolution of such known matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

NOTE 18: SUBSEQUENT EVENT

Beginning January 13, 2024, the Company's service territory encountered a severe winter weather event that included snow, ice, and high winds over several days that caused catastrophic damage to physical assets and resulted in widespread customer power outages. Along with over a dozen mutual assistance crews, PGE repaired damage and restored power to over 500,000 customers throughout the storm and the days that followed.

PGE estimates the incremental incurred and future costs to repair damage to PGE's transmission and distribution systems and restore power to customers to approximate $60 million. As a result of the historic winter storm, Oregon's Governor declared a state of emergency on January 18, 2024, which will allow PGE to seek recovery of incremental storm expenses through the previously filed emergency deferral. On February 9, 2024, PGE filed a Notice of Deferral with the OPUC, under Docket UM 2190, related to the emergency restoration costs for the January storm and expects to defer a significant portion of these expenses as regulatory assets.

Due to the storm and corresponding impact on power markets, PGE has incurred a substantial amount of incremental NVPC compared to what was anticipated in the 2024 Annual Power Cost Update Tariff (AUT). PGE believes that a portion of the storm will qualify as a Reliability Contingency Event (RCE) as approved by the OPUC in PGE's 2024 GRC. Under the RCE mechanism, PGE is allowed to pursue recovery of 80% of costs for RCEs above amounts forecasted in the Company's AUT, with the remaining 20% flowing through Operating Expenses and subject to the existing PCAM. The Company estimates total costs could be as approximately $100 million. PGE expects to defer a significant majority of these costs through its various OPUC approved mechanisms over NVPC.

PGE believes it has adequate liquidity to cover the event.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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				(9,928,905)	(808)	0	(9,929,713)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(a)]5,964,470			5,964,470		
3	Preceding Quarter/Year to Date Changes in Fair Value							0		
4	Total (lines 2 and 3)				5,964,470			5,964,470	238,863,845	244,828,315
5	Balance of Account 219 at End of Preceding Quarter/Year				(3,964,435)	(808)		(3,965,243)		
6	Balance of Account 219 at Beginning of Current Year				(3,964,435)	(808)		(3,965,243)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(b)](1,034,721)	0		(1,034,721)		
8	Current Quarter/Year to Date Changes in Fair Value							0		
9	Total (lines 7 and 8)				(1,034,721)	0		(1,034,721)	222,805,469	221,770,748
10	Balance of Account 219 at End of Current Quarter/Year				(4,999,156)	(808)		(4,999,964)		

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Comprised of the net amount of the actuarial valuation of $8,226,855 of non-qualified benefit plans net of taxes of ($2,262,385).

(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Comprised of the net amount of the actuarial valuation of ($1,427,202) of non-qualified benefit plans net of taxes of $392,480.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)	10,685,313,099	10,685,313,099					
4	Property Under Capital Leases	331,118,327	331,118,327					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	2,230,284,523	2,230,284,523					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	13,246,715,949	13,246,715,949					
9	Leased to Others							
10	Held for Future Use	48,036,748	48,036,748					
11	Construction Work in Progress	974,517,848	974,517,848					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	14,269,270,545	14,269,270,545					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,851,760,350	5,851,760,350					
15	Net Utility Plant (13 less 14)	8,417,510,195	8,417,510,195					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	5,288,576,622	5,288,576,622					
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	563,183,728	563,183,728					
22	Total in Service (18 thru 21)	5,851,760,350	5,851,760,350					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							

32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,851,760,350	5,851,760,350					

FERC FORM No. 1 (ED. 12-89)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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						0
3	(302) Franchise and Consents	188,896,603	3,400,778	0	0	0	192,297,381
4	(303) Miscellaneous Intangible Plant	641,351,214	131,527,061	4,703,797	0	0	768,174,478
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	830,247,817	134,927,839	4,703,797	0	0	960,471,859
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	3,328,862	0	0	0	0	3,328,862
9	(311) Structures and Improvements	116,300,825	0	0	0	0	116,300,825
10	(312) Boiler Plant Equipment	268,577,464	10,113,439	263,908	0	0	278,426,995
11	(313) Engines and Engine-Driven Generators						0
12	(314) Turbogenerator Units	69,558,262	0	0	0	0	69,558,262
13	(315) Accessory Electric Equipment	25,071,834	0	0	0	0	25,071,834
14	(316) Misc. Power Plant Equipment	15,843,582	(9,176,650)	0	0	0	6,666,932
15	(317) Asset Retirement Costs for Steam Production	34,911,263	0	0	0	0	34,911,263
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	533,592,092	936,789	263,908	0	0	534,264,973
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						0
19	(321) Structures and Improvements						0
20	(322) Reactor Plant Equipment						0
21	(323) Turbogenerator Units						0
22	(324) Accessory Electric Equipment						0
23	(325) Misc. Power Plant Equipment						0
24	(326) Asset Retirement Costs for Nuclear Production						0

25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	4,811,041	0	0	0	0	4,811,041
28	(331) Structures and Improvements	93,362,025	51,440,582	708,056	0	0	144,094,551
29	(332) Reservoirs, Dams, and Waterways	329,932,094	67,494,009	4,347,165	36,941	0	393,115,879
30	(333) Water Wheels, Turbines, and Generators	76,268,534	67,391,909	2,667,537	0	0	140,992,906
31	(334) Accessory Electric Equipment	34,639,612	19,854,159	1,955,456	0	0	52,538,315
32	(335) Misc. Power Plant Equipment	171,686,407	8,200	12,753	[(a)](9,294,157)	0	162,387,697
33	(336) Roads, Railroads, and Bridges	17,240,435	18,201	725,038	0	0	16,533,598
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	0	0	0	0	5,128
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	727,945,276	206,207,060	10,416,005	(9,257,216)	0	914,479,115
36	D. Other Production Plant						
37	(340) Land and Land Rights	18,150,684	0	0	[(b)](3,102,722)	0	15,047,962
38	(341) Structures and Improvements	279,279,346	8,434,923	0	24,470	0	287,738,739
39	(342) Fuel Holders, Products, and Accessories	277,725,435	240,640	0	[(c)](5,052,466)	0	272,913,609
40	(343) Prime Movers						0
41	(344) Generators	2,566,724,924	65,496,053	2,281,495	496,864	0	2,630,436,346
42	(345) Accessory Electric Equipment	145,886,047	8,676,977	325,498	14,188	0	154,251,714
43	(346) Misc. Power Plant Equipment	49,669,231	(2,289,657)	0	0	0	47,379,574
44	(347) Asset Retirement Costs for Other Production	26,802,275	1,717,315	0	0	0	28,519,590
44.1	(348) Energy Storage Equipment - Production	34,285,764	0	0	[(d)](1,452,130)	0	32,833,634
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,398,523,706	82,276,251	2,606,993	(9,071,796)	0	3,469,121,168
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,660,061,074	289,420,100	13,286,906	(18,329,012)	0	4,917,865,256
47	3. Transmission Plant						
48	(350) Land and Land Rights	17,995,731	270,990	0	0	0	18,266,721
48.1	(351) Energy Storage Equipment - Transmission						0
49	(352) Structures and Improvements	30,234,954	4,084,316	404,164	0	0	33,915,106
50	(353) Station Equipment	602,638,997	25,845,569	3,504,850	617	0	624,980,333
51	(354) Towers and Fixtures	52,987,376	272,209	0	0	0	53,259,585
52	(355) Poles and Fixtures	158,781,855	17,880,659	67,347	0	0	176,595,167
53	(356) Overhead Conductors and Devices	253,069,106	(19,250,909)	2,049	0	0	233,816,148
54	(357) Underground Conduit						0
55	(358) Underground Conductors and Devices						0
56	(359) Roads and Trails	286,332	0	0	0	0	286,332
57	(359.1) Asset Retirement Costs for Transmission Plant	34,109	0	0	0	0	34,109
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,116,028,460	29,102,834	3,978,410	617	0	1,141,153,501
59	4. Distribution Plant						
60	(360) Land and Land Rights	19,906,765	75,237	0	0	0	19,982,002
61	(361) Structures and Improvements	57,653,261	15,085,639	197,463	0	0	72,541,437
62	(362) Station Equipment	740,966,187	81,325,473	4,563,856	0	0	817,727,804
63	(363) Energy Storage Equipment – Distribution	1,577,592	1,658,159	0	0	0	3,235,751

64	(364) Poles, Towers, and Fixtures	618,142,567	129,281,859	11,263,877	0	0	736,160,549
65	(365) Overhead Conductors and Devices	814,777,131	85,875,383	636,641	0	0	900,015,873
66	(366) Underground Conduit	33,303,644	(748,279)	0	0	0	32,555,365
67	(367) Underground Conductors and Devices	1,003,224,032	59,882,058	361,883	0	0	1,062,744,207
68	(368) Line Transformers	539,658,395	27,848,061	0	0	0	567,506,456
69	(369) Services	582,071,900	13,847,260	18,089	0	0	595,901,071
70	(370) Meters	225,336,015	8,340,733	9,286	0	0	233,667,462
71	(371) Installations on Customer Premises	4,085,167	5,939,946	0	0	0	10,025,113
72	(372) Leased Property on Customer Premises						0
73	(373) Street Lighting and Signal Systems	171,460,751	29,238,890	2,752,150	0	0	197,947,491
74	(374) Asset Retirement Costs for Distribution Plant	476,732	0	0	0	0	476,732
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,812,640,139	457,650,419	19,803,245	0	0	5,250,487,313
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						0
78	(381) Structures and Improvements						0
79	(382) Computer Hardware						0
80	(383) Computer Software						0
81	(384) Communication Equipment						0
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						0
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						0
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	0	0	0	0	0	0
85	6. General Plant						
86	(389) Land and Land Rights	23,487,410	0	0	0	0	23,487,410
87	(390) Structures and Improvements	319,756,669	16,679,380	58,618	[(e)](567,954)	0	335,809,477
88	(391) Office Furniture and Equipment	128,664,321	14,458,084	22,816,893	0	0	120,305,512
89	(392) Transportation Equipment	95,882,889	14,070,899	5,717,727	0	0	104,236,061
90	(393) Stores Equipment	4,180,570	0	30,919	0	0	4,149,651
91	(394) Tools, Shop and Garage Equipment	24,482,107	1,514,191	303,867	0	0	25,692,431
92	(395) Laboratory Equipment	13,078,794	0	499,476	0	0	12,579,318
93	(396) Power Operated Equipment	45,440,476	463,678	1,365,214	0	0	44,538,940
94	(397) Communication Equipment	293,048,837	9,379,650	417,242	122,737	0	302,133,982
95	(398) Miscellaneous Equipment	2,252,124	1,488,693	868	0	0	3,739,949
96	SUBTOTAL (Enter Total of lines 86 thru 95)	950,274,197	58,054,575	31,210,824	(445,217)	0	976,672,731
97	(399) Other Tangible Property						0
98	(399.1) Asset Retirement Costs for General Plant	65,289	0	0	0	0	65,289
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	950,339,486	58,054,575	31,210,824	(445,217)	0	976,738,020
100	TOTAL (Accounts 101 and 106)	12,369,316,976	969,155,767	72,983,182	(18,773,612)	0	13,246,715,949
101	(102) Electric Plant Purchased (See Instr. 8)						0
102	(Less) (102) Electric Plant Sold (See Instr. 8)						0
103	(103) Experimental Plant Unclassified						0

104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	12,369,316,976	969,155,767	72,983,182	(18,773,612)	0	13,246,715,949

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousPowerPlantEquipmentHydraulicProductionAdjustments

Includes activities of capitalized lease assets.

(b) Concept: LandAndLandRightsOtherProductionAdjustments

Includes activities of capitalized lease assets.

(c) Concept: FuelHoldersProductsAndAccessoriesOtherProductionAdjustments

Includes activities of capitalized lease assets.

(d) Concept: EnergyStorageEquipmentProductionOtherProductionAdjustments

Includes activities of capitalized lease assets.

(e) Concept: StructuresAndImprovementsGeneralPlantAdjustments

Includes activities of capitalized lease assets.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Damascus, Clackamas County, OR	(a)	(j)	543,591
3	Sewell, Washington County, OR	(b)	(k)	2,817,507
4	Sewell Easement, Washington County, OR	(c)	(l)	332,379
5	Evergreen, Washington County, OR	(d)	(m)	3,600,000
6	Boardman, Morrow County, OR	(e)	(n)	832,853
7	Woodburn, Marion County, OR	(f)	(o)	20,290,058
8	Sunset, Washington County, OR	(g)	(p)	5,895,936
9	Berger/Majestic, Washington County, OR	(h)	(q)	13,403,236
10	Other Land and Land Rights	(i)	(r)	321,188
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				

29				
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44				
45				
46				
47	TOTAL			48,036,748

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2007

(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2008

(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2009

(d) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2019

(e) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2020

(f) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2022

(g) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2022

(h) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2023

(i) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

Various

(j) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(k) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(l) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(m) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(n) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(o) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(p) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(q) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(r) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Various

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Construct Clearwater Wind Farm	411,135,721
2	Seaside Battery Energy Storage	90,109,302
3	Build Evergreen Substation	94,604,417
4	Evergreen Battery Energy Storage	34,296,950
5	Tonquin Substation Build	24,274,847
6	Horizon-Keeler BPA #2 230kV Line	22,350,648
7	Coffee Creek - Energy Storage	19,278,051
8	Substation Communication Upgrade	19,269,740
9	Reedville Substation Rebuild	16,053,168
10	Harborton Reliability Project	17,514,738
11	Faraday Road and Drainage Improv.	13,532,091
12	ARM Replacement	12,065,989
13	Shute WJ1 and WJ2 Upgrade	10,761,337
14	Round Butte Replace Turbine Shutoff Valves	[a]9,837,396
15	Install Diesel Particulate Filters	9,337,616
16	Replace Top End Engine Parts	8,073,338
17	Memorial Substation Build	7,886,933
18	Integrated Operations Center - IOC	6,793,182
19	South Milliken 57kV Line Rebuild	6,642,896
20	Monitor Sub Rebuild (WVRP)	6,222,269
21	Long Lead Time Materials	5,754,777
22	Harrison 11kV to 13kV Conversion	4,584,028
23	Oregon City Line Center Project	4,558,090

24	BPA Substation Upgrades		4,459,000
25	Zero Trust Network Security Project		4,341,536
26	Hydro Control System Upgrade		4,002,015
27	Bethel to Round Butte Fiber		3,973,491
28	Blue Lake Distribution Feeders		3,798,303
29	Waconda Substation Expand		3,417,410
30	Round Butte Spillway Cavitation Protection		[(b)]3,381,911
31	Wildfire Mitigation Leland-Carus		3,301,680
32	Wildfire Mitigation Cherry Grove Feeder Reconstruction		3,161,209
33	Marquam Capacity Addition - Terwilliger		2,601,093
34	Clackamas River Hydro Recreation, Aesthetic & Cultural Project		2,597,434
35	Facilities Upgrades-EV Readiness		2,507,659
36	Wind Generation Fitness Program		2,437,236
37	St. Louis Substation Rebuild		2,351,649
38	Substation Equipment Replacement		2,289,661
39	Redland Substation Upgrades		2,232,259
40	Replace/Rewind Failed Transformers		2,151,093
41	OSI Energy Management System Upgrade Project		2,136,132
42	Electric Avenue Improvements		2,118,762
43	Clackamas River Hydro Habitat Mitigation and Enhancements		2,023,710
44	Beaver Modernization		1,864,110
45	Shute Feeder Reconfiguration		1,767,699
46	Biglow I Wind Enhancement Program		1,765,299
47	Upgrade Faraday Diversion Dam Infrastructure		1,709,674
48	Boeckman Road Widening		1,666,310
49	Facilities Management Fitness		1,620,368
50	Distribution Automation		1,578,237
51	ADP Upgrade Project		1,540,193
52	EV Fleet Partner Pilot		1,419,847
53	Glisan Substation Transformer Upgrade		1,371,050
54	Colstrip Coal Capital Project		[(c)]1,346,534
55	Port Westward Superheater Replacement		1,325,339
56	PGE / DTNA Heavy Duty Charging Station		1,312,111
57	Expeto Wireless Platform & Service		1,295,477
58	Additional Cap Banks and Distribution Line		1,218,841
59	Hydro Structural/Reliability Upgrades		1,199,095
60	Pelton Round Butte Mitigation Enhancement Fund		[(d)]1,062,713
61	Arleta-Holgate Line Rebuild SE PDX		1,050,102
62	Pelton Round Butte Construct Fish Facilities		[(e)]1,047,672
63	Minor Projects, <$1 million, represents 3% of the Total CWIP Balance		33,136,410
43	Total		974,517,848

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgress

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 50.01% share of the jointly owned costs is reported.

(b) Concept: ConstructionWorkInProgress

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 50.01% share of the jointly owned costs is reported.

(c) Concept: ConstructionWorkInProgress

Jointly owned with Northwestern Energy, LLC, Talen Montana, LLC, Puget Sound Energy, Inc, PacifiCorp, and Avista Corporation. Respondent's 20% share of jointly owned costs is reported.

(d) Concept: ConstructionWorkInProgress

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 50.01% share of the jointly owned costs is reported.

(e) Concept: ConstructionWorkInProgress

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 50.01% share of the jointly owned costs is reported.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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	4,993,083,347	4,993,083,347		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	361,540,625	361,540,625		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,635,829	3,635,829		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	7,565,089	7,565,089		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	372,741,543	372,741,543	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(68,279,385)	(68,279,385)		
13	Cost of Removal	(13,770,524)	(13,770,524)		
14	Salvage (Credit)	2,771,658	2,771,658		

15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(79,278,251)	(79,278,251)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Gain/(Loss)/Adjustments/Transfers	2,029,983	[(a)]2,029,983		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,288,576,622	5,288,576,622	0	0
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	456,382,796	456,382,796		
21	Nuclear Production				
22	Hydraulic Production-Conventional	305,132,145	305,132,145		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,251,369,101	1,251,369,101		
25	Transmission	429,532,561	429,532,561		
26	Distribution	2,513,948,231	2,513,948,231		
27	Regional Transmission and Market Operation				
28	General	332,211,788	332,211,788		
29	TOTAL (Enter Total of lines 20 thru 28)	5,288,576,622	5,288,576,622	0	0

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

$2,093,983 credit to accumulated reserve is due to sale of general plant assets. The depreciable plant was sold at Net Book Value for ~$2.1M. As such the reduction in accumulated reserve was less than the reduction of gross utility plant.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	121 SW Salmon Street Corporation							
2	Common Stock	04/01/1975		1,000			1,000	
3	Equity in Earnings			7,307,368	1,075,032		8,382,400	
4	Paid in Capital			77,528,661			77,528,661	
5	SubTotal			84,837,029	1,075,032	0	85,912,061	0
6	Salmon Springs Hospitality Group							

7	Common Stock	04/09/1998		10,000			10,000	
8	Equity in Earnings			(954,682)			(954,682)	
9	SubTotal			(944,682)	0	0	(944,682)	0
42	Total Cost of Account 123.1 $		Total	83,892,347	1,075,032	0	84,967,379	0

FERC FORM No. 1 (ED. 12-89)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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)	29,151,034	28,001,414	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	1,378	0	Generation
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	29,239,572	42,274,899	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	17,450,425	19,252,448	Generation
8	Transmission Plant (Estimated)	698,537	743,018	Transmission
9	Distribution Plant (Estimated)	11,295,491	15,861,078	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]1,339,679	[(b)]704,966	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	60,023,704	78,836,409	
13	Merchandise (Account 155)	0	0	
14	Other Materials and Supplies (Account 156)	0	0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)	0	0	
16	Stores Expense Undistributed (Account 163)	2,754,586	3,950,888	
17				
18				
19				
20	TOTAL Materials and Supplies	91,930,702	110,788,711	

FERC FORM No. 1 (REV. 12-05)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Balance primarily relates to costs associated with purchased renewable energy certificates (green tags).

(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Balance primarily relates to costs associated with purchased renewable energy certificates (green tags).

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	97,457		10,033		10,029		10,031		69,168		196,718	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									1,319		1,319	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													

		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
28	Total												
29	Balance-End of Year	97,457		10,033		10,029		10,031		70,487		198,037	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	1,201		193		193		193		1,884		3,664	
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales	193								193		386	
40	Balance-End of Year	1,008		193		193		193		1,691		3,278	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)		5								4		9
45	Gains												
46	Losses												

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8													

9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
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												

Name of Respondent:	This report is: (1) An Original	Date of Report:	Year/Period of Report

Portland General Electric Company	(2) A Resubmission	04/18/2024	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	Abandoned Trojan Nuclear Plant Decommissioning Costs; PGE has the authority to continue the recovery of the expenses in rates until decommissioning is complete, as authorized by OPUC (Order No. 07-015, dtd 1/12/2007)	479,948,429	8,098,685	407	[(a)](1,900,000)	138,708,705
49	TOTAL	479,948,429	8,098,685		(1,900,000)	138,708,705

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: UnrecoveredPlantAndRegulatoryStudyCostsWrittenOff

$1,900,000 - Recovery of Trojan decommissioning costs included in retail prices, until decommissioning is complete, as authorized by OPUC (Order #07-015, dtd 1/12/2007), offset in Account 407.

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Blue Lake BESS_SIS	402	561.6		
3	Pre-study for Wind and BESS interconnection	335	561.7		
4	21-105	345	561.7		
5	21-101	22,000	561.7		
6	21-102	22,093	561.7		
7	21-103	22,208	561.7		
8	21-107	111	561.7		
9	21-098	329	561.7		
10	22-107	45	561.7		
11	21-104	31,308	561.7		
12	21-105	22,179	561.7		
13	22-109	28,118	561.7		

14	22-110	219	561.7		
15	22-108	22,486	561.7		
16	LLIR SIS - PAC Dalreed	36,246	561.7		
17	LGIP System Impact Study	105,106	561.7		
18	Evergreen - 2021 RFP Negotiation	23,500	561.7		
19	Seaside - 2021 RFP Negotiation	23,500	561.7		
20	21-099	42,093	561.7		
21	21-096	1,237	561.7		
22	22-117	362	561.7		
23	22-111	249	561.7		
24	22-100	42,195	561.7		
25	23-119	93	561.7		
26	23-004	110	561.7		
27	21-101	106	561.7		
28	22-003	36,783	561.7		
29	23-230	219	561.7		
30	23-004	26,000	561.7		
31	POP: Resource Acquisition	23,500	561.7		
32	Feasibility Study Deposits	41,742	561.7		
20	Total	575,219			
21	**Generation Studies**				
39	Total				
40	Grand Total	575,219			

FERC FORM No. 1 (NEW. 03-07)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Tax Benefits Related to Book/Tax Basis Differences (Amort. period is based on the lives of the properties, approximately 25 years.)	39,788,560	1,668,649	282	640,688	40,816,521
2	Previously Flowed to Customers (Amort. period is based on the lives of the properties, approximately 25 years.)	15,092,212	632,935	283	243,020	15,482,127
3	Price Risk Management	2,035,944	748,230,995	182.3 / 254 / 547 / 555	544,130,283	206,136,656
4	Deferred Broker Settlement	(1)	57,872,841	134 / 254 / 547 / 555	57,872,839	1
5	Intervenor Funding - SB 978 (original deferral per OPUC Order No. 03-388 dtd 7/2/2003), Amortizing through 12/31/2023.	9,374	269	407.3	8,928	715
6	Intervenor Funding - CUB (original deferral per OPUC Order No. 03-388 dtd 7/2/2003), Amortizing through 12/31/2023.	398,273	132,308	407.3	327,538	203,043

7	Intervenor Funding - Match (original deferral per OPUC Order No. 03-388 dtd 7/2/2003), Amortizing through 12/31/2023.	287,237	124,907	407.3	269,439	142,705
8	Intervenor Funding - Issue (original deferral per OPUC Order No. 03-388 dtd 7/2/2003), Amortizing through 12/31/2023.	570,356	387,629	131 / 407.3	584,461	373,524
9	Intervenor Funding - JFA (original deferral per OPUC Order No. 23-033 dtd 2/8/2023)	0	179,669		0	179,669
10	Coyote Springs Major Maintenance Accrual LTSA (per OPUC GRC 95-1216, dtd 11/20/1995)	1,963,328	1,212,010	553	3,175,338	0
11	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	116,389	(102,186)	254 / 421 / 431	14,198	5
12	Glass Insulator Deferral (per OPUC Order No. 10-478 dtd 12/17/2010; UE 215 First Revenue Requirement Stipulation) Amortization period: 56 years	5,186,229	1	571	106,333	5,079,897
13	Pension Funding Postretirement Funding (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	95,200,439	8,302,196		0	103,502,635
14	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2023.	953,439	10,476,476	143 / 232 / 254 / 407.3 / 431	11,429,915	0
15	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019)	0	3,515,046	182.3 / 232 / 254 / 431	3,365,277	149,769
16	CET Deferral (2014-2018 vintages) (amortization per OPUC Order No. 17-511, dtd 12/18/17), Amortizing through 1/31/2023.	292,980	195,961	421 / 431 / 903	488,941	0
17	Schedule 110 Energy Efficiency (per OPUC Advice No. 10-01), Amortizing through 12/31/2023.	1	804,946	143 / 182.3 / 254	804,947	0
18	Deferred Cost - FLEX Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2023.	(8,113)	9,478,949	143 / 182.3 / 232 / 254 / 407.3 / 431	9,468,736	2,100
19	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2023.	1	18,775,091	143 / 182.3 / 232 / 254 / 407.3 / 431	18,775,092	0
20	Gresham Privilege Tax Collection Deferral (Advice No. 17-05, Schedule 134, dtd 02/24/17), Amortizing through 1/31/2023.	37,853	166,239	407.3 / 421	204,092	0
21	Portland Harbor Environmental Remediation Deferral (Per OPUC Order No. 17-071, Docket No. UM1789, dtd 03/02/17)	32,754,737	4,921,899	107 / 143 / 421 / 923	2,499,356	35,177,280
22	Decoupling Deferral - 2020 (UM 1417)	1,594,745	56,566	254 / 456	1,651,311	0
23	Debt Issuance (Interest Rate Hedges for Long Term Debt Amortization period: 30 years beginning April 2019)	4,115,007	0	428.1	156,264	3,958,743
24	Transportation Electrification Prgm (UM 1938), Amortizing through 12/31/2023.	396,888	1,560,032	143 / 182.3 / 232 / 254 / 421 / 431 / 908	1,954,988	1,932
25	EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Amortizing through 12/31/2023.	394,298	3,564,709	182.3 / 232 / 254 / 431 / 908	3,959,007	0
26	HB-2165 (UM 2218), Amortizing through 12/31/2023.	0	30,393	182.3 / 232 / 254	30,393	0
27	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2023.	1,304,937	18,576,924	431 / 903	19,949,603	(67,742)
28	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017), Amortizing through 12/31/2023.	314,594	2,745,186	232 / 254 / 407.3 / 431	3,059,780	0
29	Community Solar (Per UM-1977, OPUC Order No. 18-477, dtd 12/19/2018), Amortizing through 12/31/2023.	3,244,961	3,023,151	232 / 407.3 / 555	5,152,721	1,115,391
30	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order No. 10-198 dtd 5/28/2010) (Reauthorized OPUC Order No. 15-185 dtd 6/09/2015), Amortizing through 12/31/2023.	0	6,099,244	182.3 / 254	5,993,514	105,730
31	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020), Amortizing through 12/31/2023.	110,081	828,003	232 / 254 / 431 / 908	930,525	7,559
32	Wheatridge Renewable Energy Farm (Per UE-370, Order No. 20-279, dtd 8/26/2020), Amortizing through 12/31/2023.	1,477,742	4	553	52,936	1,424,810
33	Labor Day Wildfire - Emergency Widlfie Deferral (Per UM-2115, Order No. 20-389, dtd 10/27/2020), Amortizing through 12/31/2029.	32,404,319	3,062,525	407.3 / 421 / 571 / 593	6,939,348	28,527,496
34	COVID-19 (Per UM-2064, Order No. 20-376, dtd 10/27/2020),	21,822,549	2,470,766	421 / 904	10,594,362	13,698,953

	Amortization period 4/1/2023-3/31/2025.					
35	Oregon Commercial Activity Tax - OCAT (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020)	(1)	1		0	0
36	OPUC Fee Deferral (Per UM-2046, Order No. 20-411, dtd 11/05/2020), Amortizing through 12/31/2023.	2,086,942	1,576,477	407.3	2,150,167	1,513,252
37	February 2021 Ice Storm - Emergency Restoration Costs (Per UM 2156, filing dtd 2/15/2021), Amortizing through 12/31/2029.	77,952,617	8,137,470	407.3 / 421 / 593	17,488,823	68,601,264
38	Decoupling Deferral - 2021 (UM 1417, Amortization period 1/1/2023-12/31/2023)	9,196,637	447,071	456	9,327,941	315,767
39	Direct Access 2021 (Per UM-1301, Order No. 21-034, dtd 1/28/2021)	15,962	704	447	16,666	0
40	Microgrid Storage (UM 2113, Order No. 20-370), Amortizing through 12/31/2023.	1,352,871	60,147	407.3	1,306,851	106,167
41	Independent Evaluator (UM-2184)	246,840	586,890	232 / 421	212,139	621,591
42	PCAM 2021 (UE-395), Amortizing through 12/31/2024.	29,276,447	6,387,676	555 / 421	19,970,498	15,693,625
43	Wildfire Mitigation Plan (UM-2019)	28,503,868	62,292,672	107 / 143 / 232 / 571 / 580 / 593	60,578,390	30,218,150
44	Decoupling Deferral - 2022 (UM 1417, Amortization period 1/1/2024-12/31/2024)	3,642,483	2,227,081	456	41,910	5,827,654
45	Direct Access 2022 (UM 1301), Amortizing through 12/31/2023.	812,148	36,073	447	773,150	75,071
46	Lease Obligation Balancing Account	11,967,150	12,395,353	547	60,193	24,302,310
47	Colstrip Decommissioning Deferral (UE-394, 5/09/2022), Amortizing through 12/31/2023.	86,986	91,330	456	98,999	79,317
48	KB Pipeline MMA (UE-394, 5/09/2022, amortization of 5 years)	38,422	48,007	182.3 / 553	86,429	0
49	Level III Storm (UE-394), Amortizing through 12/31/2024.	7,050,000	17,284,992	229 / 593	20,809,992	3,525,000
50	CBIAG Deferral (UM 2249) Advice No. 22-36. Amortizing through 12/31/2023.	0	308,151	232 / 431 / 908	266,820	41,331
51	Research & Development Tax Credits (Per UM-1991, OPUC Order No. 18-464 dtd 12/14/2018)	0	632,000	254	632,000	0
52	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	0	6,154,339	182.3 / 553	3,996,386	2,157,953
53	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017), Amortizing through 6/30/2023.	0	208,882		0	208,882
54	Monet NVPC QF Deferral 2023 (UM 1988)	0	648,000		0	648,000
55	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001), Amortizing through 12/31/2023.	0	2,503,891		0	2,503,891
56	Time of Day (TOD) - Deferral 2023 (Per Advice No. 23-40, Special Condition No. 6)	0	818,426		0	818,426
57	Time of Day (TOD) - Deferral 2024 (Per Advice No. 23-40, Special Condition No. 6)	0	304,880		0	304,880
44	TOTAL	434,088,731	1,032,144,846		852,651,527	613,582,050

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line	Description of Miscellaneous Deferred Debits	Balance at Beginning of Year	Debits	CREDITS		Balance at End of Year
				Credits Account	Credits Amount	

No.	(a)	(b)	(c)	Charged (d)	(e)	(f)
1	Misc. Undistributed Charges	186,519	2,100,055	Various	1,800,483	486,091
2	Net Co-owner / Trust Contribution	477,322	38,883,789	Various	39,760,714	(399,603)
3	Deferred Revolving Credit Agreement Fees (amort through Sept 2028)	2,431,390	961,000	431	547,437	2,844,953
4	Dispatchable Generation (various amort periods from 2013 and extending through 2032)	5,969,289	2,558	903	1,427,061	4,544,786
5	Utility Property Sales - Selling Expenses	(9,076)	2,029,983	Various	2,029,983	(9,076)
47	Miscellaneous Work in Progress	681,139				1,035,318
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	9,736,583				8,502,469

FERC FORM No. 1 (ED. 12-94)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Related	298,110,021	300,657,360
3	Regulatory Liabilities	73,511,236	22,827,800
4	Employee Benefits	98,922,231	99,302,381
5	Price Risk Management	53,555,944	66,106,884
6	Tax Credits & NOL's	103,846,457	74,160,732
7	Other	[a]3,688,789	2,854,701
8	TOTAL Electric (Enter Total of lines 2 thru 7)	631,634,678	565,909,858
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	[b]9,048,520	7,643,304
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	640,683,198	573,553,162

Notes

FERC FORM NO. 1 (ED. 12-88)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 7 - Other	2022	2023

Bad Debt Expense	3,347,172	2,614,744
Deferred Revenue	1,107,805	1,107,505
Nuclear Decommissioning Trust	9,627,992	10,090,950
Renewable Energy Development	(620,588)	(2,264,977)
Finance Lease Liability	(10,802,621)	(10,173,570)
Miscellaneous	1,029,030	1,480,049
Total - Line 7 - Other	3,688,789	2,854,701

(b) Concept: AccumulatedDeferredIncomeTaxes

Line 17 - Other Non-Utility	**2022**	**2023**
Property Related	9,071,820	7,732,285
Employee Benefits	(23,301)	(88,980)
Total - Line 17 - Other Non-Utility	9,048,520	7,643,304

FERC FORM NO. 1 (ED. 12-88)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	160,000,000			101,159,609	1,753,903,725				
7	Total	160,000,000			101,159,609	1,753,903,725				
8	Preferred Stock (Account 204)									
9	No Par Value Cumulative Preferred	30,000,000								
12	Total	30,000,000				0				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

FERC FORM NO. 1 (ED. 12-91)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2024-04-18	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	4,804,482
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	4,804,482
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	1,556,498
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	1,556,498
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	12,428,738
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	12,428,738
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	0
40	Total	18,789,718

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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	Common Stock	23,113,532
22	TOTAL	23,113,532

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	6.875% SERIES VI DUE 8-1-2033	221	50,000,000		519,257	0	437,500	08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500
3	6.26% SERIES DUE 5-1-2031	221	100,000,000		723,856	0	0	05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000
4	6.31% SERIES DUE 5-1-2036	221	175,000,000		1,270,565	0	0	05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,500
5	5.80% SERIES DUE 6-1-2039	221	170,000,000		1,460,968	0	0	05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,000
6	5.81% SERIES DUE 10-1-2037	221	130,000,000		1,109,574	0	517,518	09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,000
7	$150mm 5.43% SERIES DUE 5-3-2040	221	150,000,000		1,034,284	0	0	11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000
8	$150mm 4.47% SERIES DUE 6/15/2044	221	150,000,000		1,113,047	0	0	06/07/2013	06/15/2044	06/07/2013	06/15/2044	150,000,000	6,705,000
9	$75mm 4.47% SERIES DUE 8/14/2043	221	75,000,000		558,740	0	0	08/29/2013	08/14/2043	08/29/2013	08/14/2043	75,000,000	3,352,500
10	$50mm 4.84% SERIES DUE 12/15/2048	221	50,000,000		311,154	0	0	12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000
11	$100mm 4.39% SERIES DUE 8-15-2045	221	100,000,000		645,383	0	0	08/15/2014	08/15/2045	08/15/2014	08/15/2045	100,000,000	4,390,000
12	$100mm 4.44% SERIES DUE 10-15-2046	221	100,000,000		625,030	0	0	10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,426,111
13	$75mm 3.55% SERIES DUE 1/15/2030	221	75,000,000		325,295	0	0	01/15/2015	01/15/2030	01/15/2015	01/15/2030	75,000,000	2,662,500
14	$70mm 3.50% SERIES DUE 5/15/2035	221	70,000,000		305,128	0	0	05/15/2015	05/15/2035	05/15/2015	05/15/2035	70,000,000	2,450,000
15	$150mm 3.98% Series Due 11/21/2047	221	150,000,000		(99,510)	0	0	11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000
16	$75mm 3.98% Series Due 8/3/2048	221	75,000,000		(44,757)	0	0	08/03/2017	08/03/2048	08/03/2017	08/03/2048	75,000,000	2,985,000
17	$75mm 4.47 Series Due 12/11/2048	221	75,000,000		336,938	0	0	12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	3,352,500
18	$200mm 4.3% Series Due 4-11- 2049	221	200,000,000		860,461	0	0	04/19/2019	04/11/2049	04/19/2019	04/11/2049	200,000,000	8,600,000
19	$110mm 3.34%% Series Due 10-15-2049	221	110,000,000		477,767	0	0	10/15/2019	10/15/2049	10/15/2019	10/15/2049	110,000,000	3,674,000
20	$160mm 3.34% Series Due 1-15-2050	221	160,000,000		694,934	0	0	11/15/2019	01/15/2050	11/15/2019	01/15/2050	160,000,000	5,344,000
21	$200mm 3.15% Series Due 4-1-2030	221	200,000,000		862,049	0	0	04/27/2020	04/01/2030	04/27/2020	04/01/2030	200,000,000	6,300,000
22	$160mm 1.84% Series Due 12-10-2027	221	160,000,000		645,816	0	0	12/10/2020	12/10/2027	12/10/2020	12/10/2027	160,000,000	2,944,000

23	$70mm 2.32% Series Due 12-10-2032	221	70,000,000		278,000	0	0	12/10/2020	12/10/2032	12/10/2020	12/10/2032	70,000,000	1,624,000
24	$100mm 1.82% Series Due 9-30-2028	221	100,000,000		452,981	0	0	09/30/2021	09/30/2028	09/30/2021	09/30/2028	100,000,000	1,825,056
25	$50mm 2.10% Series Due 9-30-2031	221	50,000,000		226,490	0	0	09/30/2021	09/30/2031	09/30/2021	09/30/2031	50,000,000	1,052,917
26	$100mm 2.20% Series Due 1-15-2034	221	100,000,000		452,981	0	0	09/30/2021	01/15/2034	09/30/2021	01/15/2034	100,000,000	2,200,000
27	$150mm 2.97% Series Due 9-30-2051	221	150,000,000		679,471	0	0	09/30/2021	09/30/2051	09/30/2021	09/30/2051	150,000,000	4,467,375
28	$100mm 5.47% Series Due 11-30-2029	221	100,000,000		438,003	0	0	11/30/2022	11/30/2029	11/30/2022	11/30/2029	100,000,000	5,374,667
29	$100mm 5.56% Series Due 11-30-2033 comm auth 22-031 2/10/2022	221	100,000,000		477,010	0	0	01/13/2023	01/13/2033	01/13/2023	01/13/2033	100,000,000	5,485,194
30	$50m 5.44% Series Due 09-15-2030 comm auth 22-031 2/10/2022	221	50,000,000		202,658	0	0	08/29/2023	09/15/2030	08/29/2023	09/15/2030	50,000,000	929,334
31	$150m 5.48% Series Due 9-15-2033 comm auth 22-031 2/10/2022	221	150,000,000		607,974	0	0	08/29/2023	09/15/2033	08/29/2023	09/15/2033	150,000,000	2,808,500
32	$100m 5.68% Series Due 9-15-2038 comm auth 22-031 2/10/2022	221	100,000,000		405,316	0	0	09/14/2023	09/15/2038	09/14/2023	09/15/2038	100,000,000	1,672,444
33	$100m 5.78% Series Due 11-15-2053 comm auth 22-031 2/10/2022	221	100,000,000		145,316	0	0	11/15/2023	11/15/2053	11/15/2023	11/15/2053	100,000,000	738,556
34	$100m 5.83% Series Due 11-15-2059 comm auth 22-031 2/10/2022	221	100,000,000		145,316	0	0	11/15/2023	11/15/2059	11/15/2023	11/15/2059	100,000,000	744,944
35	$97.8mm CITY FORSYTH 2.125% DUE 05-01-2033	221	97,800,000		528,702	(1,956,000)	0	03/11/2020	05/01/2033	03/11/2020	05/01/2033	97,800,000	2,078,250
36	$21.0mm CITY FORSYTH 2.375% DUE 05-01-2033	221	21,000,000		97,594	0	0	03/11/2020	05/01/2033	03/11/2020	05/01/2033	21,000,000	498,750
37	$80mm 3.51% SERIES DUE 11-15-2024	221	80,000,000		501,502	0	0	11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000
38	$105mm 4.74% SERIES DUE 11/15/2042	221	105,000,000		652,029	0	0	11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000
39	Subtotal		3,998,800,000		20,027,322	(1,956,000)	955,018					3,998,800,000	151,158,598
40	Reacquired Bonds (Account 222)												
41													
42													
43													
44	Subtotal											0	
45	Advances from Associated Companies (Account 223)												
46													
47													
48													
49	Subtotal											0	
50	Other Long Term Debt (Account 224)												
51	$260M 4.5% SERIES DUE TO 10-1-2023	224	260,000,000		406,149	0	0	10/21/2022	10/22/2023	10/21/2022	10/22/2023	0	2,282,605
52	Subtotal		260,000,000		406,149	0	0					0	2,282,605

33	TOTAL		4,258,800,000										3,998,800,000	153,441,203

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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)	222,805,469
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	56,651,590
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	399,376,004
11	Other	[a]55,726,679
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	31,947,622
16	Regulatory Credits	184,402,231
17	Regulatory Debits	158,132,248
18	Other	[b]4,150,565
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	127,618,947
21	State & Local Tax Deduction	27,895,632
22	Other	[c]816,452
27	Federal Tax Net Income	199,596,045
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	41,915,173
30	PTC	(30,043,680)
31	R&D Federal	(1,521,972)
32	RTA Federal Tax Adjustment	1,739,202
33	Prior Period Adjustment	(1,363,764)
34	Other Items Affecting Tax	(86,841)
35	Total Federal Income Tax - PGE	10,638,117

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Line 12 - Deductions Recorded on Books Not Deducted for Return	
Qualified NDT	1,681,467
Meals & Entertainment	686,000
Political Activity	1,187,925
Bad Debts	(2,642,061)
Fines and Penalties	26,119
Employee Benefits	12,553,721
Federal Tax Expense	14,584,766
Orion Contingent Royalty Payments	6,529
Tax Finance Lease	2,261,417
Unamortized Loss on Reacquired Debt	1,254,601
State & Local Tax Expense	29,562,687
Deferred Revenue	441,422
Wheatridge RECs	(4,802,882)
Miscellaneous	(1,075,032)
Total Other	**55,726,679**

(b) Concept: IncomeRecordedOnBooksNotIncludedInReturn

Line 18 - Income Recorded on Books Not Included in Return	
Key Man Insurance Proceeds	(2,695,608)
OCI	(1,427,203)
Miscellaneous	(27,755)
Total Other	(4,150,566)

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Line 22 - Deductions on Return Not Charged Against Book Income	
Dividends Received Deduction	(31,000)
Prepaid	40
Renewable Energy Initiatives	2,399,593
Property Tax	(3,223,427)
Miscellaneous	38,342
Total Other	**(816,452)**

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	FERC Resale/Coord	Federal Tax	Federal	2023	281,871	0	1,250,669	1,253,831	0	278,709	0	0	0	0	1,250,669
2	Income Tax	Federal Tax	Federal	2023	0	4,035,501	10,638,455	7,206,726	0	0	603,772	9,247,886	0	0	1,390,569

3	Foreign Insurance Excise Tax	Federal Tax	Federal	2023	0	0	0	0	0	0	0	82,323	0	0	(82,323)
4	FICA (Employer Share)	Federal Tax	Federal	2023	1,306,233	0	32,122,415	31,827,325	0	1,601,323	0	14,831,170	0	0	17,291,245
5	Unemployment	Federal Tax	Federal	2023	(17,591)	0	135,347	216,162	0	(98,406)	0	68,436	0	0	66,911
6	Power License	Federal Tax	Federal	2023	223,187	(345,786)	3,172,131	3,349,867	0	366,923	(24,314)	0	0	0	3,172,131
7	**Subtotal Federal Tax**				1,793,700	3,689,715	47,319,017	43,853,911	0	2,148,549	579,458	24,229,815	0	0	23,089,202
8	Income Tax	Income Tax	Montana	2023	0	(565,471)	402,545	550,000	0	0	(418,016)	388,248	0	0	14,297
9	County & City Income Tax	Income Tax	Oregon	2023	0	1,558,828	1,390,621	1,487,853	0	0	1,656,060	1,353,483	0	0	37,138
10	**Subtotal Income Tax**				0	993,357	1,793,166	2,037,853	0	0	1,238,044	1,741,731	0	0	51,435
11	Electric Energy Producers Tax	Other License And Fees Tax	Montana	2023	189,351	0	768,589	766,789	0	191,151	0	448,759	0	0	319,830
12	**Subtotal Other License And Fees Tax**				189,351	0	768,589	766,789	0	191,151	0	448,759	0	0	319,830
13	Department of Energy	Other Taxes and Fees	Oregon	2023	0	1,225,277	2,500,196	2,385,514	0	0	1,110,595	2,500,549	0	0	(353)
14	Public Utility Comm Fees	Other Taxes and Fees	Oregon	2023	0	0	11,620,424	11,620,424	0	0	0	0	0	0	11,620,424
15	Department of Enviro Quality	Other Taxes and Fees	Oregon	2023	145,787	0	229,091	187,439	0	187,439	0	0	0	0	229,091
16	Water Power Fee	Other Taxes and Fees	Oregon	2023	0	131,807	686,563	989,001	1	0	434,244	0	0	0	686,563
17	Goods & Services Tax	Other Taxes and Fees	Canada	2023	(162)	0	0	0	0	(162)	0	0	0	0	0
18	**Subtotal Other Taxes and Fees**				145,625	1,357,084	15,036,274	15,182,378	1	187,277	1,544,839	2,500,549	0	0	12,535,725
19	Property Taxes	Property Tax	Montana	2023	2,993,599	0	4,361,357	5,277,677	0	2,077,279	0	3,649,544	0	0	711,813
20	Property Taxes	Property Tax	Oregon	2023	0	39,570,133	82,115,829	84,751,529	0	0	42,205,833	79,401,381	0	0	2,714,448
21	Property Taxes	Property Tax	Washington	2023	2,479,206	0	1,165,414	1,913,376	0	1,731,244	0	1,165,414	0	0	0
22	**Subtotal Property Tax**				5,472,805	39,570,133	87,642,600	91,942,582	0	3,808,523	42,205,833	84,216,339	0	0	3,426,261
23	Corp Excise Tax and CAT	Excise Tax	Oregon	2023	243,008	3,380,914	23,063,722	19,236,941	0	243,008	(445,867)	22,530,083	0	0	533,639
24	**Subtotal Excise Tax**				243,008	3,380,914	23,063,722	19,236,941	0	243,008	(445,867)	22,530,083	0	0	533,639
25	City Taxes & Licenses	Franchise Tax	Oregon	2023	3,893,788	0	55,729,593	55,615,100	0	4,008,281	0	55,689,435	0	0	40,158
26	Corporate Franchise Tax	Franchise Tax	California	2023	0	(1,782,522)	864,277	1,328,042	0	0	(1,318,757)	855,690	0	0	8,587
27	**Subtotal Franchise Tax**				3,893,788	(1,782,522)	56,593,870	56,943,142	0	4,008,281	(1,318,757)	56,545,125	0	0	48,745
28	Unemployment	Payroll Tax	Oregon	2023	516,690	0	10,247,739	9,215,122	0	1,549,307	0	2,234,062	0	0	8,013,677
29	Transportation Tax	Payroll Tax	Oregon	2023	3,353	0	2,380,670	2,308,150	1	75,874	0	1,203,753	0	0	1,176,917
30	Workers Comp Assessment	Payroll Tax	Oregon	2023	18	0	608,337	608,337	0	18	0	159,348	0	0	448,989
31	**Subtotal Payroll Tax**				520,061	0	13,236,746	12,131,609	1	1,625,199	0	3,597,163	0	0	9,639,583
32	Other State Income Tax	State Tax	Various	2023	0	(1,025)	0	9,443	0	0	8,418	0	0	0	0
33	**Subtotal State Tax**				0	(1,025)	0	9,443	0	0	8,418	0	0	0	0
40	TOTAL				12,258,338	47,207,656	245,453,984	242,104,648	2	12,211,988	43,811,968	195,809,564		0	49,644,420

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Tenant security deposits	160,000	232	676		159,324
2	Deferred Liability for Transferred Non-Qualified Plan Benefits	497,934	421	18,372		479,562
3	Reserve for Environmental Remediation Costs	4,000,000				4,000,000
4	Clean Fuels Program OPUC 17-250 and 17-512	21,024,422	232,926	8,400,689	17,818,468	30,442,201
5	Wireless Mods & Make Ready Clearing	1,817,020	186	120,300		1,696,720
6	Equity Forward Transaction Credit	769,137	214,921	770,033	896	0
7	AED: Grant Implementation	0			10,000	10,000
47	TOTAL	28,268,513		9,310,070	17,829,364	36,787,807

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	841,673,575	120,003,216	87,311,398			182	24,616,151	254	26,319,884	876,069,126
3	Gas	0									0
4	Other (Specify)	0									0
5	Total (Total of lines 2 thru 4)	841,673,575	120,003,216	87,311,398				24,616,151		26,319,884	876,069,126
6											
7											
8		0									0
9	TOTAL Account 282 (Total of Lines 5 thru 8)	841,673,575	120,003,216	87,311,398				24,616,151		26,319,884	876,069,126
10	Classification of TOTAL										
11	Federal Income Tax	670,747,008	81,482,187	61,302,532			182	16,066,256	254	17,431,099	692,291,506
12	State Income Tax	169,771,327	37,414,339	25,346,117			182	5,848,374	254	5,762,209	181,753,384
13	Local Income Tax	1,155,240	1,106,690	662,749			182	2,701,521	254	3,126,576	2,024,236

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Property Related	14,608,207					254	9,024,501	182.3	9,141,963	14,725,669
4	Price Risk Management	107,073,800	45,358,588	102,319,976				2,846,466		1,300,203	48,566,149
5	Regulatory Assets	[(a)]92,837,279	122,938,998	119,589,820				3,418,488		3,412,479	96,180,448
6	Regulatory Liabilities										
7	Other	[(b)]15,981,885	881,639	418,686				41,882		377,496	16,780,452
9	TOTAL Electric (Total of lines 3 thru 8)	230,501,171	169,179,225	222,328,482	0	0		15,331,337		14,232,141	176,252,718
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[(c)]8,643,119			3,481,363	2,228,002	254	67,226	182.3	105,971	9,935,225
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	239,144,290	169,179,225	222,328,482	3,481,363	2,228,002		15,398,563		14,338,112	186,187,943
20	Classification of TOTAL										
21	Federal Income Tax	165,973,666	120,602,297	158,641,212	2,477,484	1,602,253		6,622,733		6,701,159	128,888,408
22	State Income Tax	66,420,279	48,269,656	63,494,286	992,902	621,884		2,267,678		2,299,067	51,598,056
23	Local Income Tax	6,750,345	307,272	192,984	10,977	3,865		6,508,152		5,337,886	5,701,479

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Regulatory Assets:	Beginning Balance	Ending Balance
ASC 715 Pension & Post Retirement	26,365,869	28,657,427

ASC 980 Mark-to-Market	563,857	17,540,735
Miscellaneous	(1,245,026)	(86,720)
Decoupling	2,667,144	960,668
CET Deferral	(179,348)	(256,231)
Feed in Tariff (FIT)	19,593,545	21,276,988
Portland Harbor (PHERA)	8,057,810	8,325,655
Covid-19	5,850,641	3,327,888
Wildfire	6,165,269	91,750
Storm Deferral	17,722,644	13,156,358
PCAM Deferral	7,274,874	3,185,930
Subtotal Regulatory Assets	**92,837,279**	**96,180,448**

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Utility):	Beginning Balance	Ending Balance
Prepaid Property Tax	10,483,489	11,291,514
Unamortized Loss on Reacquired Debt	4,802,474	4,453,808
Local Flow-Through Deferred Income Tax	695,922	1,035,130
Subtotal Other (Utility)	**15,981,885**	**16,780,452**

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Non-Utility):	Beginning Balance	Ending Balance
Prepaid Property Tax	7,673,897	9,491,534
Unamortized Loss on Reacquired Debt	411,337	197,177
Local Flow-Through Deferred Income Tax	557,885	246,514
Subtotal Other (Non-Utility)	**8,643,119**	**9,935,225**

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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 Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Income Taxes	248,746,382	190	16,379,816	696,121	233,062,687
2	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001), Amortizing through 12/31/2023.	517,375	407.4 / 421	579,847	11,136	(51,336)
3	Boardman Severance (Advice No.14-18, dtd 11/3/2014)	5,108,616	242 / 254 / 456	5,337,193	228,577	0
4	Asset Retirement Obligations: Balancing Account	4,176,640	407.3	6,532,201	5,010,204	2,654,643
5	Boardman ARO	2,845,989	108 / 242 / 254 / 407.3 / 456	30,729,881	28,901,697	1,017,805
6	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	2,661,125	232 / 254 / 456 / 553	7,999,513	5,338,388	0
7	Colstrip Major Maintenance Deferral (Per OPUC UE-319, Order No. 17-511, dtd 12/18/17)	5,053,643	254 / 456	629,351	842,803	5,267,095
8	Port Westward 1 Major Maint Deferral (Per OPUC UE 262, Order No. 13-459, dtd 12/9/2013)	3,549,217	232 / 254 / 456 / 553	5,250,229	4,453,957	2,752,945
9	Port Westward 2 Major Maintenance Deferral (Per OPUC 2015 GRC Docket UE-283, OPUC Order No.14-422, dtd 12/4/2014)	4,549,361	254 / 456	1,110,869	773,806	4,212,298
10	Zero Interest Program Loan Repayments (Per Advice No. 05-19 dtd 12/20/2005)	66,732	254	1	61,908	128,639
11	Schedule 110 Energy Efficiency - Balancing Account (Per Advice No. 07-25 dtd 5/20/2008), Amortizing through 12/31/2023.	1,447,428	182.3 / 254 / 431	1,438,964	1,244,342	1,252,806
12	Sunway 3 Investment Deferral (Per UM 1480 dtd 4/01/2010; Amortization over 20 years commencing 2010)	340,990	407.4	45,480	0	295,510
13	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017), Amortizing through 6/30/2023.	1,754,622	182.3 / 254 / 407 / 421	2,341,952	583,883	(3,447)
	PRC Acquisition (Per OPUC UE-283 Final GRC Order No.14-					

14	422, dtd 12/04/2014, Second Partial Stipulation dtd 9/2/2014)	3,683,226	242 / 254	3,809,947	126,721	0
15	Deferred Broker Settlement	6,644,360	182.3	18,962,359	15,182,907	2,864,908
16	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order 10-198 dtd 5/28/2010 reauthorized OPUC Order 15-185 dtd 6/09/2015), Amortizing through 12/31/2023.	3,004,636	182.3 / 254 / 421	5,887,818	2,883,182	0
17	Price Risk Management	195,275,294	182.3 / 254 / 547 / 555	208,630,694	13,355,400	0
18	Monet NVPC QF Deferral-2019 (Per UE-335 NVPC Stipulation, OPUC Order No. 18-405)	1	254	1	0	0
19	Research & Development Tax Credits (Per UM-1991, OPUC Order No. 18-464 dtd 12/14/2018), Amortizing through 1/31/2023.	(411,778)	182.3 / 190 / 254 / 407.4 / 411.1 / 421 / 431 / 923	2,490,793	3,810,072	907,501
20	Postretirement Plans (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	7,088,311	219 / 926	7,223,915	3,073,905	2,938,301
21	Lease Obligation Balancing Account	(1)		0	1	0
22	OCAT (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020).	974,749	182.3 / 254 / 407.3	996,461	3,527,599	3,505,887
23	Monet NVPC QF Deferral 2020 (Per UM-1988, Order No. 19-441 dtd 12/20/2019)	384,362	254 / 431	384,362	0	0
24	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019)	936,627	182.3 / 254 / 421	5,530,249	4,593,623	1
25	Deferred Cost - FLEX Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2023.	1,221,187	182.3 / 254	3,072,228	4,098,498	2,247,457
26	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2023.	0	254	111,333	1,238,844	1,127,511
27	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2023.	480,447	182.3 / 254	2,104,078	2,326,974	703,343
28	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017), Amortizing through 12/31/2023.	(156,518)	182.3 / 254	156,519	1,411,235	1,098,198
29	Decoupling Deferral - 2021 (UM 1417, Amortization period 1/1/2023-12/31/2023)	(2)		0	2	0
30	Wheatridge RECs (UE 391), Amortizing through 12/31/2023.	4,638,686	232 / 555	4,816,467	5,169,527	4,991,746
31	Decoupling Deferral - 2022 (UM 1417, Amortization period 1/1/2024-12/31/2024)	1,367,226	182.3 / 242 / 421 / 449	1,411,432	44,206	0
32	Transportation Electrification (UM 1938), Amortizing through 12/31/2022.	0	182.3 / 254	442,820	668,829	226,009
33	HB-2165 (UM 2218), Amortizing through 12/31/2023.	5,419,723	182.3 / 232 / 254 / 908 / 921	3,990,997	8,947,376	10,376,102
34	Monet NVPC QF Deferral 2021 (UM 1988), Amortizing through 12/31/2023.	0	555	228,504	347,307	118,803
35	Monet NVPC QF Deferral 2022 (UM 1988)	127,034	555	27,479	7,161	106,716
36	Regional Power Act (RPA)	33,408		0	0	33,408
37	TRC Revenue Deferral (OATT Deferral)	0	232	2,535,387	2,535,387	0
38	Direct Access 2023 (Per UM-1301)	0		0	2,715,256	2,715,256
39	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	0		0	202,744	202,744
40	EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Amortizing through 12/31/2023.	0		0	599,146	599,146
41	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2023.	0		0	52,906	52,906
42	KB Pipeline MMA (UE-394, 5/09/2022, amortization of 5 years)	0	456	36,028	56,671	20,643
43	CBIAG Deferral (UM 2249) Advice No. 22-36. Amortizing through 12/31/2023.	0		0	315,767	315,767
44	Coyote Springs Major Maintenance Accrual LTSA (per OPUC	0	456	665,212	809,218	144,006

	GRC 95-1216, dtd 11/20/1995)					
45	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020), Amortizing through 12/31/2023.	0		0	316,261	316,261
41	TOTAL	511,529,098		351,890,380	126,563,547	286,202,265

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	1,208,401,408	1,103,142,961	7,952,313	8,088,474	815,920	809,573
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[a]790,602,966	[e]718,662,203	6,557,723	6,541,949	112,469	112,401
5	Large (or Ind.) (See Instr. 4)	[b]367,911,469	[f]311,063,785	4,578,148	4,228,987	266	269
6	(444) Public Street and Highway Lighting	13,078,454	12,274,623	43,544	45,651	204	201
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,379,994,297	2,145,143,572	19,131,728	18,905,061	928,859	922,444
11	(447) Sales for Resale	476,723,920	431,426,146	7,803,299	6,745,270	45	43
12	TOTAL Sales of Electricity	2,856,718,217	2,576,569,718	26,935,027	25,650,331	928,904	922,487
13	(Less) (449.1) Provision for Rate Refunds	(14,313,659)	(23,353,262)				
14	TOTAL Revenues Before Prov. for Refunds	2,871,031,876	2,599,922,980	26,935,027	25,650,331	928,904	922,487
15	Other Operating Revenues						
16	(450) Forfeited Discounts	6,862,843	2,462,939				
17	(451) Miscellaneous Service Revenues	[c]1,541,350	[g]874,209				
18	(453) Sales of Water and Water Power	(28,980)	(25,917)				
19	(454) Rent from Electric Property	18,968,002	15,711,403				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[d]62,261,243	[h]75,460,751				
22	(456.1) Revenues from Transmission of Electricity of Others	5,914,686	8,017,820				

23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	95,519,144	102,501,205				
27	TOTAL Electric Operating Revenues	2,966,551,020	2,702,424,185				

Line12, column (b) includes $ 4,038,000 of unbilled revenues.
Line12, column (d) includes (78,470) MWH relating to unbilled revenues

FERC FORM NO. 1 (REV. 12-05)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $7,631,920 in revenue related to the delivery of 577,115 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregons electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utilitys remaining energy customers. For 2023, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $18,532,651 in revenue related to the delivery of 1,715,095 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2023, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

(c) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 Charges as Defined by the Rules and Regulations and Miscellaneous Charges and Schedule 320 Meter Information Services. Schedule 300 charges recorded to this account include the following:

E-Manager & Energy Experts

Field Service Charges

Meter Tamper/Test Charges

NWCPUD Scheduling

Reconnect Charges

Returned Check Charges

(d) Concept: OtherElectricRevenue

Other Electric Revenues consist of the following:	Q4-2023
Boardman Decommissioning Balancing Account	1,256
Boardman Inventory Write-Off	11,319
Boardman Severance	(44,018)
Carty - Major Maint Accrual/Defr	2,754,488
Colstrip - Major Maint Accrual/Defr	(213,452)
Colstrip Decommissioning	(10,284)
Coyote Springs - Major Maint Accrual/Defr	(144,006)
Customers Attaching PGE Poles	65,501
Firm PTP Prepayment	314,362
Gain(Loss) on Gas Resale	(783,923)
General Parks & Recreation	7,941
Hydro License Implementation and Compliance	1,115,513
Joint Affected System Study	180,000
KB Pipeline MMA Deferral	(20,644)
Lost Revenue Recovery	(1,005,911)
MCI Metro	760,421
Other	544,581
PW1 - Major Maint Deferral	796,273
PW2 - Major Maint Deferral	337,064
RPA Balancing	57,012,382
Sch. 32 Norm Adj	(4,503,256)
Sch. 7 Norm Adj	(114,000)
Sch. 83 Norm Adj	(2,417,092)
Steam Sales	4,365,520
Transmission Resale	2,981,210
Transmission Study Fees	270,000
Grand Total	62,261,243

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $11,824,361 in revenue related to the delivery of 547,844 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregon's electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2022, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $22,238,171 in revenue related to the delivery of 1,777,633 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2022, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

(g) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 Charges as Defined by the Rules and Regulations and Miscellaneous Charges and Schedule 320 Meter Information Services. Schedule 300 charges recorded to this account include the following:

E-Manager & Energy Experts

Field Service Charges

Meter Tamper/Test Charges

NWCPUD Scheduling

Reconnect Charges

Returned Check Charges

(h) Concept: OtherElectricRevenue

Other Electric Revenues consist of the following:	Q4-2022
Boardman Decommissioning Balancing Account	(115,203)
Boardman Inventory Write-Off	89,860
Boardman Severance	36,207
Carty Major Maintenance Deferral	(1,057,014)
Colstrip - Major Maint Accrual/Defr	(625,616)
Colstrip Decommissioning	85,787
Gain(Loss) on Gas Resale	7,455,082
General Parks & Recreation	2,363
Hydro License Implementation and Compliance	1,051,065
Lost Revenue Recovery	2,767,952
MCI Metro	3,883,684
Other	1,276,372
PW1 - Major Maint Deferral	(136,465)
PW2 - Major Maint Deferral	(768,720)
RPA Balancing	57,715,912
Sch. 32 Norm Adj	(1,078,860)
Sch. 7 Norm Adj	1,110,273
Sch. 83 Norm Adj	(5,747,801)
Steam Sales	5,059,402
Transmission Resale	4,456,470
Grand Total	75,460,751

FERC FORM NO. 1 (REV. 12-05)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	7-Residential Service	8,018,442	1,209,053,883	815,920	9,827.4855	0.1508
2	15-Outdoor Area Lighting	1,640	770,525			0.4698
41	TOTAL Billed Residential Sales	8,020,082	1,209,824,408	815,920	9,829.4955	0.1508
42	TOTAL Unbilled Rev. (See Instr. 6)	(67,769)	(1,423,000)			0.021
43	TOTAL	7,952,313	1,208,401,408	815,920	9,746.4372	0.152

FERC FORM NO. 1 (ED. 12-95)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.
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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	15-Outdoor Area Lighting	11,583	2,977,386			0.257
2	32-Small Nonresidential	1,555,718	230,279,015	94,994	16,377.0133	0.148
3	38-Large Nonresidential	26,088	4,137,293	345	75,617.3913	0.1586
4	47-Small Irrigation & Drainage	21,258	4,920,812	2,749	7,732.9938	0.2315
5	49-Large Irrigation & Drainage	60,390	10,837,517	1,266	47,701.4218	0.1795
6	83-Large Nonresidential	2,835,889	324,326,446	11,402	248,718.5581	0.1144
7	85-Large Nonresidential	2,011,046	198,387,697	1,236	1,627,059.8706	0.0986
8	89-Large Nonresidential	14,384	1,311,374	1	14,384,000	0.0912
9	485-Large Nonresidential COS	22,820	2,896,518	13	1,755,384.6154	0.1269
10	485-Large Nonresidential DAS	0	8,497,198	203	0	
11	489-Large Nonresidential DAS	0	585,815	1	0	
12	515-Outdoor Area Lighting DAS	0	510	0		
13	532-Small Nonresidential DAS	0	113,535	126	0	
14	538-Large Nonresidential DAS	0	1,188	2	0	
15	583-Large Nonresidential DAS	0	(156,605)	95	0	
16	585-Large Nonresidential DAS	0	(1,263,733)	36	0	
41	TOTAL Billed Small or Commercial	6,559,176	787,851,966	112,469	58,319.857	0.1201
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(1,453)	2,751,000			(1.8933)
43	TOTAL Small or Commercial	6,557,723	[(a)]790,602,966	112,469	58,306.9379	0.1206

FERC FORM NO. 1 (ED. 12-95)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $7,631,920 in revenue related to the delivery of 577,115 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregons electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utilitys remaining energy customers. For 2023, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

FERC FORM NO. 1 (ED. 12-95)

Page 304

Name of Respondent:	This report is: (1) An Original	Date of Report:	Year/Period of Report

Portland General Electric Company	(2) A Resubmission	04/18/2024	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	85-Large Nonresidential	593,932	53,289,716	162	3,666,246.9136	0.0897
2	89-Large Nonresidential	1,123,198	88,425,945	20	56,159,900	0.0787
3	90-Large Nonresidential	2,832,601	200,779,770	6	472,100,166.6667	0.0709
4	485-Large Nonresidential	13,037	1,412,478	1	13,037,000	0.1083
5	489-Large Nonresidential	23,180	2,401,752	1	23,180,000	0.1036
6	689-Large Nonresidential	1,448	273,095	1	1,448,000	0.1886
7	485-Large Nonresidential DAS	0	5,709,101	50	0	
8	489-Large Nonresidential DAS	0	11,432,754	19	0	
9	585-Large Nonresidential DAS	0	(287,640)	3	0	
10	689-Large Nonresidential DAS	0	1,764,498	3	0	
41	TOTAL Billed Large (or Ind.) Sales	4,587,396	365,201,469	266	17,245,849.6241	0.0796
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(9,248)	2,710,000			(0.293)
43	TOTAL Large (or Ind.)	4,578,148	[(a)] 367,911,469	266	17,211,082.7068	0.0804

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $18,532,651 in revenue related to the delivery of 1,715,095 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2023, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.
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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	91-Street & Hwy Lighting	11,863	4,866,490	186	63,779.5699	0.4102

2	92-Traffic Signals	2,737	236,006	16	171,062.5	0.0862
3	95-Street & Hwy Lighting (New	28,944	7,975,958	2	14,472,000	0.2756
41	TOTAL Billed Public Street and Highway Lighting	43,544	13,078,454	204	213,450.9804	0.3004
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	43,544	13,078,454	204	213,450.9804	0.3004

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Other Sales to Public Authorities					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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)
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41	TOTAL Billed Sales To Railroads and Railways					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Interdepartmental Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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	Transmission Rate Case	0	(14,313,659)			
41	TOTAL Billed Provision For Rate Refunds	0	(14,313,659)	0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(14,313,659)			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

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)
41	TOTAL Billed - All Accounts	19,210,198	2,375,956,297	928,859	20,681.5006	0.1237
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(78,470)	4,038,000			(0.0515)
43	TOTAL - All Accounts	19,131,728	2,379,994,297	928,859	20,597.0206	0.1244

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)	Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Alberta Electric System Operator (AESO)	SF	[b]				631	0	70,209	0	70,209
2	Altop Energy Trading LLC	SF	WSPP-1				1,600	0	153,500	0	153,500
3	Arizona Public Service Co.	SF	WSPP-1				600	0	140,250	0	140,250
4	Avangrid Renewables (was Iberdrola)	SF	EEI				57,858	0	4,272,560	0	4,272,560
5	Atlas Energy, LLC	SF	EEI				596,193	0	33,450,042	0	33,450,042
6	Avista Corp.	SF	WSPP-1				5,201	0	232,707	0	232,707
7	BP Energy Company	SF	PGE-11				1,112	0	140,063	0	140,063
8	Bonneville Power Administration	SF	WSPP-1				1,067,151	0	83,407,597	0	83,407,597
9	British Columbia Hydro & Power Authoirty	SF	WSPP-1				25	0	0	0	0
10	Brookfield Energy Marketing LP	SF	WSPP-1				26,654	0	1,889,324	0	1,889,324
11	California Independent System Operator	SF	CAISO				1,651,398	0	60,399,238	0	60,399,238
12	Calpine Energy Services, L.P.	SF	EEI				162,576	0	9,356,545	0	9,356,545
13	Chelan County, PUD No. 1, Washington	SF	WSPP-1				815	0	31,495	0	31,495
14	Citigroup Energy Inc.	SF	WSPP-1				14,000	0	1,452,708	0	1,452,708
15	City of Anaheim	OS	WSPP-1				0	0	0	[d] 1,750,000	1,750,000
16	City of Burbank	SF	WSPP-1				1,245	0	164,250	0	164,250
17	City of Glendale	SF	WSPP-1				2,030	0	238,000	0	238,000
18	City of Roseville	SF	WSPP-1				233	0	11,300	0	11,300
19	Clatskanie Peoples Utility District	SF	WSPP-1				5,236	0	256,990	0	256,990
20	Clean Power Alliance	OS	WSPP-1				0	0	0	[e] 1,800,000	1,800,000
21	ConocoPhillips Company	SF	WSPP-1				12,695	0	909,925	0	909,925
22	CP Energy Marketing (US) Inc	SF	WSPP-1				5,394	0	574,360	0	574,360
23	Direct Energy Business Marketing	OS	WSPP-1				0	0	0	[f] 750,000	750,000
24	Douglas County, PUD No. 1, Washington	LU	WSPP-1				1,139,774	0	12,910,939	0	12,910,939
25	Dynasty Power	SF	WSPP-1				117,486	0	8,374,389	0	8,374,389
26	EAST BAY COMMUNITY ENERGY AUTHORITY	OS	WSPP-1				0	0	0	[g] 18,525,000	18,525,000

27	EDF Trading North America, LLC	SF	WSPP-1				22,774	0	2,307,448	0	2,307,448
28	Energy Keepers, Inc.	SF	WSPP-1				10,378	0	778,068	0	778,068
29	ENMAX Energy Marketing Inc.	SF	EEI				555	0	55,775	0	55,775
30	Eugene Water & Electric Board	SF	WSPP-1				6,122	0	748,774	0	748,774
31	Exelon Generation Company, LLC	SF	EEI				16,945	0	1,186,209	0	1,186,209
32	Exelon Generation Company, LLC	OS	EEI				0	0	0	(h) 3,000,000	3,000,000
33	Gridforce Energy Management	SF	NWPP				719	0	59,889	0	59,889
34	Guzman Energy LLC	SF	WSPP-1				14,594	0	789,991	0	789,991
35	Idaho Power Company	SF	WSPP-1				196,877	0	15,620,715	0	15,620,715
36	Load Balance Energy	OS	OATT				4,883	0	0	0	0
37	Macquarie Energy LLC	SF	WSPP-1				54,369	0	3,141,937	0	3,141,937
38	Mercuria Energy America, LLC	SF	WSPP-1				160,477	0	9,634,148	0	9,634,148
39	Merrill Lynch Commodities	SF	WSPP-1				4,000	0	337,944	0	337,944
40	Morgan Stanley Capital Group, Inc.	SF	PGE-11				189,841	0	12,022,854	0	12,022,854
41	Marin Clean Energy	OS	WSPP-1				0	0	0	(i) 1,625,000	1,625,000
42	NaturEner Power Watch, LLC	SF	NWPP				56	0	2,670	0	2,670
43	NorthWestern Corporation	SF	WSPP-1				39,554	0	4,160,064	0	4,160,064
44	PacifiCorp	SF	EEI				104,709	0	6,137,558	0	6,137,558
45	PacifiCorp	LU	PGE-11				16,988	0	(c) 79,092	0	79,092
46	Powerex Corp.	SF	EEI				1,372,471	0	86,772,382	0	86,772,382
47	Orange County	OS	WSPP-1				0	0	0	(j) 2,250,000	2,250,000
48	Phillips 66 Energy Trading LLC	SF	WSPP-1				3,800	0	182,856	0	182,856
49	Public Utility District No. 1 of Clark County	SF	WSPP-1				3,600	0	363,600	0	363,600
50	Public Utility District No. 2 of Grant County	SF	WSPP-1				54,004	0	4,970,138	0	4,970,138
51	Public Service Company of Colorado	SF	WSPP-1				1,621	0	471,800	0	471,800
52	Puget Sound Energy	SF	WSPP-1				20,152	0	962,731	0	962,731
53	Rainbow Energy Marketing Company	SF	WSPP-1				1,338	0	52,530	0	52,530
54	San Jose Clean Energy	OS	WSPP-1				0	0	0	(k) 2,225,000	2,225,000
55	Sacramento Municipal Utility District	SF	WSPP-1				1,054	0	117,927	0	117,927
56	Sacramento Municipal Utility District	OS	WSPP-1				0	0	0	(l) 1,350,000	1,350,000
57	Seattle City Light	SF	WSPP-1				5,606	0	353,016	0	353,016
58	Shell Energy North America (US), L.P.	SF	PGE-11				152,820	0	10,938,722	0	10,938,722
59	Shell Energy North America (US), L.P.	OS	WSPP-1				0	0	0	(m) 4,175,000	4,175,000
60	Snohomish County, PUD No.1, Washington	SF	WSPP-1				8,822	0	601,990	0	601,990
61	Sonoma Clean Power Authority	OS	WSPP-1				0	0	0	(n) 2,000,000	2,000,000
62	Southern California Edison	SF	EEI				21,154	0	4,151,015	0	4,151,015
63	Tacoma Power	SF	WSPP-1				914	0	63,793	0	63,793
64	Tenaska Power Services Co.	SF	WSPP-1				100	0	698,375	0	698,375
65	The Energy Authority, Inc.	SF	WSPP-1				23,372	0	1,525,095	0	1,525,095
66	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI				197,161	0	13,657,931	0	13,657,931
67	TransCanada Energy Sales Ltd.	SF	WSPP-1				12,781	0	635,981	0	635,981
68	Vitol Inc.	SF	WSPP-1				208,781	0	38,759,582	0	38,759,582

69	Direct Access deferral 2022						0	0	0	[o](2,744,649)	(2,744,649)
70	Direct Access Deferral						0	0	0	[p](760,422)	(760,422)
71	[a] Portland General Electric Total	SF	OA96137	220.19			0	0	0	0	0
15	Subtotal - RQ										0
16	Subtotal-Non-RQ						7,803,299	0	440,778,991	35,944,929	476,723,920
17	Total						7,803,299	0	440,778,991	35,944,929	476,723,920

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Represents Portland General Electric Companys use of Portland General Electric Company's Open Access Transmission System. This is included in Account 447 based on guidance from FERC Deputy Chief Accountant - issued January 1996.

(b) Concept: RateScheduleTariffNumber

Electricity sold to Alberta Electric System Operator under Canadian tariff, no FERC tariff involved.

(c) Concept: EnergyChargesRevenueSalesForResale

Estimated Round Butte plant operating expenses (Cov Dam replacement power).

(d) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(e) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(f) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(g) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(h) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(i) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(j) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(k) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(l) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(m) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(n) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits

(o) Concept: OtherChargesRevenueSalesForResale

Defer costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.

(p) Concept: OtherChargesRevenueSalesForResale

Amortization of deferred costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	(184,198)	67,296
5	(501) Fuel	48,621,978	44,841,981
6	(502) Steam Expenses	1,833,604	1,828,295
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	3,329,744	3,361,485
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	53,601,128	50,099,057
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	361,016	651,732
16	(511) Maintenance of Structures	989,089	986,889
17	(512) Maintenance of Boiler Plant	7,928,015	6,560,047
18	(513) Maintenance of Electric Plant	707,045	920,669
19	(514) Maintenance of Miscellaneous Steam Plant	678,451	598,588
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	10,663,616	9,717,925
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	64,264,744	59,816,982
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		

38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	492,820	452,297
45	(536) Water for Power	628,018	602,289
46	(537) Hydraulic Expenses	7,510,409	7,072,210
47	(538) Electric Expenses	2,066,432	2,074,183
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,322,249	3,758,251
49	(540) Rents	1,184,410	1,158,024
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	15,204,338	15,117,254
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	538,154	453,548
54	(542) Maintenance of Structures	0	3,850
55	(543) Maintenance of Reservoirs, Dams, and Waterways	908,643	830,005
56	(544) Maintenance of Electric Plant	1,162,927	1,844,923
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,028,513	2,248,651
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,638,237	5,380,977
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	19,842,575	20,498,231
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	4,066,606	3,556,159
63	(547) Fuel	342,068,772	144,392,430
64	(548) Generation Expenses	17,766,638	12,798,448
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	13,819,783	12,747,056
66	(550) Rents	445,135	905,333
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	378,166,934	174,399,426
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,376,757	2,949,558
70	(552) Maintenance of Structures	471,034	520,384
71	(553) Maintenance of Generating and Electric Plant	44,425,815	38,267,489
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,062,729	1,064,659
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	48,336,335	42,802,090
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	426,503,269	217,201,516
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	777,351,053	785,500,386

76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	271,108	461,916
78	(557) Other Expenses	27,132,622	27,203,025
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	804,754,783	813,165,327
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,315,365,371	1,110,682,056
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,378,440	6,174,805
85	(561.1) Load Dispatch-Reliability	17,296	16,746
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,574,577	1,487,115
87	(561.3) Load Dispatch-Transmission Service and Scheduling	2,093,541	2,005,381
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	237,602	
90	(561.6) Transmission Service Studies	402	
91	(561.7) Generation Interconnection Studies	574,815	367,118
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	341,550	396,280
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	470,672	455,909
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	105,365,945	105,560,413
97	(566) Miscellaneous Transmission Expenses	(3,198,359)	(4,050,064)
98	(567) Rents	3,166,516	1,932,296
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	117,022,997	114,345,999
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	6,503	14,685
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	1,039,524	336,353
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,530,913	1,397,813
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	4,593,349	3,524,011
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	7,170,289	5,272,862
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	124,193,286	119,618,861
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		

116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	24,206,115	28,496,163
135	(581) Load Dispatching	1,149,996	863,050
136	(582) Station Expenses	2,038,686	2,155,925
137	(583) Overhead Line Expenses	3,175,367	3,270,062
138	(584) Underground Line Expenses	4,673,855	4,446,988
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	196,111	454,043
140	(586) Meter Expenses	3,406,006	3,251,812
141	(587) Customer Installations Expenses	1,874,740	1,747,747
142	(588) Miscellaneous Expenses	10,771,426	10,864,197
143	(589) Rents	1,475,545	876,816
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	52,967,847	56,426,803
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	158,167	139,431
147	(591) Maintenance of Structures	311,339	249,159
148	(592) Maintenance of Station Equipment	5,665,633	5,428,633
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	117,148,533	109,428,061
150	(594) Maintenance of Underground Lines	13,106,998	10,895,925
151	(595) Maintenance of Line Transformers	758,711	652,225
152	(596) Maintenance of Street Lighting and Signal Systems	523,919	794,138
153	(597) Maintenance of Meters	15,032	45,533
154	(598) Maintenance of Miscellaneous Distribution Plant	9,577,341	8,227,185

155	TOTAL Maintenance (Total of Lines 146 thru 154)	147,265,673	135,860,290
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	200,233,520	192,287,093
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	84,968	563,280
161	(903) Customer Records and Collection Expenses	50,269,699	51,954,851
162	(904) Uncollectible Accounts	13,685,188	6,985,302
163	(905) Miscellaneous Customer Accounts Expenses	5,229,586	5,747,354
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	69,269,441	65,250,787
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	28,557,075	28,506,165
169	(909) Informational and Instructional Expenses	1,644,319	1,129,811
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	30,201,394	29,635,976
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	108,668,690	99,378,424
182	(921) Office Supplies and Expenses	16,082,212	19,835,486
183	(Less) (922) Administrative Expenses Transferred-Credit	21,252,417	15,790,312
184	(923) Outside Services Employed	17,637,354	22,639,583
185	(924) Property Insurance	11,137,408	10,366,271
186	(925) Injuries and Damages	6,021,871	6,101,935
187	(926) Employee Pensions and Benefits	49,091,471	47,092,682
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	14,817,937	11,981,778
190	(929) (Less) Duplicate Charges-Cr.	3,277,091	2,866,377
191	(930.1) General Advertising Expenses	820,207	790,722
192	(930.2) Miscellaneous General Expenses	14,307,259	14,549,800
193	(931) Rents	3,900,473	3,876,795
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	217,955,374	217,956,787
195	Maintenance		

196	(935) Maintenance of General Plant	4,737,713	4,595,843
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	222,693,087	222,552,630
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,961,956,099	1,740,027,403

FERC FORM NO. 1 (ED. 12-93)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	Airport Solar, LLC	LU	201				112,330	0	0	0	0	8,653,504	0	8,653,504
2	Alkali Solar	LU	201				25,875	0	0	0	0	2,543,913	0	2,543,913
3	Altop Energy Trading	LU	201				1,600	0	0	0	0	72,704	0	72,704
4	Avangrid Renewables (was Iberdrola)	SF	PGE-11				305,785	0	0	0	0	17,708,916	0	17,708,916
5	Avangrid Renewables (was berdrola Renewables)	LU	PGE-11				203,688	0	0	0	0	13,194,578	0	13,194,578
6	Avangrid Renewables (was Iberdrola)	LU	PGE-11				0	0	0	0	3,120,000	0	0	3,120,000
7	Avista Corp. - AVWP (was WWP)	SF	WSPP-1				152,794	0	0	0	0	11,443,178	0	11,443,178

8	Atlas Enery	SF	EEI				209,158	0	0	0	0	16,921,552	0	16,921,552
9	BP Energy Company	SF	PGE-11				2,338	0	0	0	0	3,677	0	3,677
10	Black Hills Power	LU	201				800	0	0	0		80,000	0	80,000
11	Brightwood Solar	LU	201				15,788	0	0	0	0	1,297,457	0	1,297,457
12	Ballston Solar	LU	201				3,648	0	0	0	0	357,540	0	357,540
13	Bellevue Solar	LU	Bellevue				0	0	0	0	0	151,855	0	151,855
14	Bonneville Power Administration	SF	WSPP-1				629,646	0	0	0	0	66,045,066	0	66,045,066
15	Bonneville Power Administration	LF	WSPP-1				937,315	0	0	0	0	71,170,481	0	71,170,481
16	Bonneville Power Administration	SF	WSPP-1				0	0	0	0	9,024,000	0	0	9,024,000
17	Boring Solar	LU	201				3,805	0	0	0	0	371,895	0	371,895
18	Brookfield Energy Marketing	SF	WSPP-1				100,570	0	0	0	0	6,718,231	0	6,718,231
19	CP Energy Marketing (US)	SF	WSPP-1				16,282	0	0	0	0	1,428,821	0	1,428,821
20	California Independent System Operator	SF	CAISO				1,407,747	0	0	0	0	52,755,763	0	52,755,763
21	Public Utility District No. 1 of Clark County	SF	WSPP-1				0	0	0	0	0	(815)	0	(815)
22	Calpine Energy Services	SF	PGE-11				902,249	0	0	0	0	65,904,089	0	65,904,089
23	Case Creek Solar	LU	201				3,884	0	0	0	0	415,643	0	415,643
24	Bristol Solar LLC	LU	201				4,538	0	0	0	0	63,778	0	63,778
25	Butler Solar	LU	201				7,722	0	0	0	0	756,411	0	756,411
26	Chelan County, PUD No. 1, Washington	SF	WSPP-1				67,006	0	0	0	0	5,484,289	0	5,484,289
27	Citigroup Energy	SF	WSPP-1				98,000	0	0	0	0	6,994,980	0	6,994,980
28	Clatskanie County PUD	SF	WSPP-1				3,313	0	0	0	0	219,437	0	219,437
29	Clearwater East	SF	WSPP-1				25,576	0	0	0		573,985	0	573,985
30	Columbia Basin Electric Cooperative Inc.	LU	OATT				879	0	0	0	0	129,189	0	129,189
31	ConocoPhillips	SF	WSPP-1				36,551	0	0	0	0	3,548,223	0	3,548,223
32	Covanta Marion	LU	QF83-118				48,708	0	0	0	0	2,828,373	0	2,828,373
33	Day Hill Solar	LU	201				3,871	0	0	0	0	317,103	0	317,103
34	Dynasty Power Inc.	SF	WSPP-1				22,297	0	0	0	0	2,103,049	0	2,103,049
35	Douglas County, PUD No. 1, Washington	(b) LF	WSPP-1				1,115,240	0	0	0	0	38,453,232	0	38,453,232
36	Douglas County, PUD No. 1, Washington	SF	WSPP-1				0	0	0	0	2,649,919	0	0	2,649,919
37	EDF Trading North America, LLC	SF	WSPP-1				46,672	0	0	0	0	2,915,326	0	2,915,326
38	Energy Keepers, Inc. - ENKP	SF	WSPP-1				17,239	0	0	0	0	1,331,686	0	1,331,686
39	ENMAX Energy Marketing	LU	PGE-11				2,201	0	0	0		168,324	0	168,324
40	ESI Vansycle Partners, LP	LU	WSPP-1				62,040	0	0	0	0	4,659,910	0	4,659,910
41	Eugene Water & Electric Board	LU	WSPP-1				0	0	0	0	(86,000)	0	0	(86,000)
42	Eugene Water & Electric Board	SF	ER94-717				8,457	0	0	0	0	437,456	0	437,456
43	Evergreen Biomass	LU	201				39,038	0	0	0	0	3,868,770	0	3,868,770
44	Exelon Generation Co.	SF	WSPP-1				34,347	0	0	0	0	1,725,645	0	1,725,645
45	Falls Creek Hydro	LU	201				12,792	0	0	0	0	1,145,837	0	1,145,837

46	Finley BioEnergy, LLC	LU	201				31,920	0	0	0	0	1,303,076	0	1,303,076
47	Fort Rock Solar 1	LU	201				25,931	0	0	0	0	2,570,084	0	2,570,084
48	Fort Rock Solar 4	LU	201				25,423	0	0	0	0	2,501,345	0	2,501,345
49	Gridforce Energy Management - GRID	SF	201				13	0	0	0	0	884	0	884
50	Idaho Power Company	SF	NWPP				67,715	0	0	0	0	2,698,875	0	2,698,875
51	Lake Oswego Corporation	LU	201				186	0	0	0		4,625	0	4,625
52	Labish Solar	LU	WSPP-1				3,953	0	0	0	0	325,016	0	325,016
53	Macquarie Cook Power	SF	201				268,191	0	0	0	0	26,215,004	0	26,215,004
54	Mercuria Energy America, LLC	SF	WSPP-1				61,583	0	0	0	0	7,129,494	0	7,129,494
55	Merrill Lynch Commodities	LU	201				200	0	0	0		15,800	0	15,800
56	Milford Solar	LU	201				4,299	0	0	0	0	472,012	0	472,012
57	Middlefork Irrigation District	LU	201				15,180	0	0	0	0	505,622	0	505,622
58	Morgan Stanley Capital Group	SF	PGE-11				23,770	0	0	0	0	1,600,494	0	1,600,494
59	Montague Solar	OS	WSPP-1				313,992	0	0	0	0	17,098,019	0	17,098,019
60	NextEra Energy Power Marketing, LLC	SF	WSPP-1				0	0	0	0	0	0	0	0
61	Nevada Power Company	SF	WSPP-1				6,772	0	0	0	0	209,953	0	209,953
62	NorthWestern Corporation	SF	WSPP-1				41,121	0	0	0	0	2,266,450	0	2,266,450
63	Norwest Energy 14	LU	201				3,784	0	0	0	0	138,128	0	138,128
64	Obsidian Lakeview	LU	201				25,706	0	0	0	0	2,562,154	0	2,562,154
65	OE Solar 3, LLC	LU	201				26,414	0	0	0	0	2,504,646	0	2,504,646
66	Okanogan County PUD, Washington	(c) LF	WSPP-1				137,839	0	0	0	0	12,162,543	0	12,162,543
67	O'Neil Solar	LU	201				3,884	0	0	0	0	381,184	0	381,184
68	Outback Solar	LU	Outback				7,757	0	0	0	0	777,738	0	777,738
69	Pacific Northwest Generating Company	SF	WSPP-1				43,607	0	0	0	0	4,023,721	0	4,023,721
70	PacifiCorp	SF	PGE-11				11,628	0	0	0	0	515,642	0	515,642
71	Palmer Creek Solar	LU	201				3,951	0	0	0	0	388,431	0	388,431
72	Pika Solar	LU	201				3,352	0	0	0	0	(495)	0	(495)
73	PaTu Wind	LU	WSPP-1				24,864	0	0	0	0	2,283,818	0	2,283,818
74	Phillips 66 Energy Trading LLC	LU	201				1,612	0	0	0		158,683	0	158,683
75	Duus Solar (Alchemy)	LU	201				38,706	0	0	0	0	4,095,174	0	4,095,174
76	Portland, City of	LU	#2821				70,157	0	0	0	0	2,946,751	0	2,946,751
77	Powerex	SF	PGE-11				24,240	0	0	0	0	3,730,800	0	3,730,800
78	Public Service Co of Colorado	SF	WSPP-1				465	0	0	0	0	26,575	0	26,575
79	Grant County, PUD No. 2, Washington	LU	Wanapum				626,540	0	0	0	0	44,980,865	0	44,980,865
80	Grant County, PUD No. 2, Washington	LU	Priest Rapids				626,540	0	0	0	0	32,134,492	0	32,134,492
81	Grant County, PUD No. 2, Washington	SF	WSPP-1				95,354	0	0	0	0	773,015	0	773,015
82	Greenpark Solar, LLC	LU	201				1,884	0	0	0	0	33,535	0	33,535
83	Guzman Energy LLC	SF	WSPP-1				5,971	0	0	0	0	763,051	0	763,051
84	City of Glendale	SF	WSPP-1				130	0	0	0	0	7,360	0	7,360

85	Puget Sound Energy	SF	WSPP-1				178,533	0	0	0	0	12,855,153	0	12,855,153
86	Rafael Solar	LU	201				3,812	0	0	0	0	373,756	0	373,756
87	Riley Solar	LU	201				25,243	0	0	0	0	2,492,499	0	2,492,499
88	Rainbow Energy Marketing Company	SF	WSPP-1				4,095	0	0	0	0	226,325	0	226,325
89	Rock Garden Solar	LU	201				25,106	0	0	0	0	2,462,032	0	2,462,032
90	Roseville, City of	LU	201				10	0	0	0		50	0	50
91	Seattle City Light	SF	WSPP-1				15,916	0	0	0	0	992,476	0	992,476
92	Shell Energy	SF	WSPP-1				242,180	0	0	0	0	20,072,511	0	20,072,511
93	Sheep Solar	LU	201				3,447	0	0	0	0	215,064	0	215,064
94	Silverton Solar	LU	201				3,737	0	0	0	0	210,993	0	210,993
95	Sacramento Municipal Utility District	SF	WSPP-1				1,577	0	0	0	0	122,320	0	122,320
96	Snohomish County, PUD No. 1, Washington	SF	WSPP-1				36,455	0	0	0	0	1,463,897	0	1,463,897
97	SP Solar 1, LLC	LU	201				3,446	0	0	0	0	209,668	0	209,668
98	SP Solar 5, LLC	LU	201				3,726	0	0	0	0	1,464,051	0	1,464,051
99	SP Solar 6, LLC	LU	201				3,497	0	0	0	0	206,751	0	206,751
100	SP Solar 7, LLC	LU	201				3,561	0	0	0	0	190,788	0	190,788
101	SP Solar 8, LLC	LU	201				3,346	0	0	0	0	229,918	0	229,918
102	SSD Clackamas 1	LU	201				6,484	0	0	0	0	760,453	0	760,453
103	SSD Clackamas 4	LU	201				4,073	0	0	0	0	161,758	0	161,758
104	SSD Clackamas 7	LU	201				3,794	0	0	0	0	155,511	0	155,511
105	SSD Marion 1	LU	201				2,997	0	0	0	0	63,108	0	63,108
106	SSD Marion 3	LU	201				3,265	0	0	0	0	149,503	0	149,503
107	SSD Marion 5	LU	201				3,990	0	0	0	0	130,404	0	130,404
108	SSD Marion 6	LU	201				3,740	0	0	0	0	133,697	0	133,697
109	Steel Bridge	LU	201				3,067	0	0	0	0	27,565	0	27,565
110	Starvation Solar 1 LLC	LU	201				24,477	0	0	0	0	2,408,436	0	2,408,436
111	St Louis Solar	LU	201				4,113	0	0	0	0	402,715	0	402,715
112	Suluss Solar 35	LU	201				4,666	0	0	0	0	88,594	0	88,594
113	Suluss Solar 33	LU	201				4,682	0	0	0	0	89,091	0	89,091
114	Suluss Solar 22	LU	201				4,681	0	0	0	0	98,069	0	98,069
115	Suluss Solar 25	LU	201				3,390	0	0	0	0	61,654	0	61,654
116	Suluss Solar 28	LU	201				4,470	0	0	0	0	94,180	0	94,180
117	Suluss Solar 29	LU	201				3,830	0	0	0	0	62,268	0	62,268
118	Suluss Solar 17	LU	201				4,252	0	0	0	0	84,720	0	84,720
119	Suntex Solar	LU	201				23,140	0	0	0	0	2,258,034	0	2,258,034
120	West Hines Solar	LU	201				25,279	0	0	0	0	2,467,699	0	2,467,699
121	Tacoma, City of	SF	WSPP-1				6,501	0	0	0	0	419,979	0	419,979
122	Tenaska Power Services	SF	WSPP-1				0	0	0	0	0	(13,243)	0	(13,243)
123	The Energy Authority	SF	WSPP-1				40,320	0	0	0	0	2,478,873	0	2,478,873
124	Thomas Creek Solar	LU	201				4,006	0	0	0	0	324,724	0	324,724
125	Tickle Creek	LU	201				3,106	0	0	0	0	220,831	0	220,831

126	TransAlta Energy Marketing	SF	PGE-11				116,493	0	0	0	0	9,836,903	0	9,836,903
127	Turlock Irrigation District	SF	WSPP-1				23,130	0	0	0	0	957,928	0	957,928
128	Vitol Inc.	SF	WSPP-1				24,845	0	0	0	0	4,836,825	0	4,836,825
129	Volcano Solar	LU	201				1,421	0	0	0	0	102,496	0	102,496
130	VON FAMILY LTD PARTNERSHIP	LU	201				3	0	0	0	0	964	0	964
131	Warm Springs Power Enterprises	SF	WSPP-1				0	0	0	0	0	0	0	0
132	Warm Springs Power Enterprises	LU	WSPP-1				625,094	0	0	0	0	47,279,198	0	47,279,198
133	Warm Springs Power Enterprises	LU	WSPP-1				0	0	0	0	6,000,000	0	0	6,000,000
134	Wheatride Solar	LU	WSPP-1				125,445	0	0	0	0	(163,021)	0	(163,021)
135	Wheatridge Wind II, LLC	LU	WSPP-1				563,818	0	0	0	0	26,129,873	0	26,129,873
136	Kale Patch Solar	LU	201				3,857	0	0	0	0	316,774	0	316,774
137	Drift Creek	LU	201				13,012	0	0	0	0	1,075,755	0	1,075,755
138	Yamhill Solar	LU	Yamhill				0	0	0	0	0	123,244	0	123,244
139	[(a)] Load Balance Energy	OS	OATT				160,582	0	0	0	0	0	0	0
140	Country Village Estates	[(d)] OS	201				0	0	0	0	0	347,824	0	347,824
141	Domaine Drouhin	[(e)] OS	201				55	0	0	0	0	(33,342)	0	(33,342)
142	Starbuck Properties	[(f)] OS	201				27	0	0	0	0	1	0	1
143	Solar Payment Option	[(g)] OS	215-217				16,330	0	0	0	0	5,904,431	0	5,904,431
144	Tualatin Valley Water Dist	[(h)] OS	201				259	0	0	0	0	76	0	76
145	Green Power						0	0	0	0	0	0	16,636,486	[(i)] 16,636,486
146	NVPC MONET QF Deferrals						0	0	0	0	0	0	(903,983)	[(j)] (903,983)
147	Margin on Electric Financials						0	0	0	0	0	0	(22,591,759)	[(k)] (22,591,759)
148	Pelton Round Butte Financial Lease 49.9%						0	0	0	0	0	0	2,096,618	[(l)] 2,096,618
149	2021 PCAM Deferrals	AD					0	0	0	0	0	0	14,761,030	[(m)] 14,761,030
150	REC Retirement Expense						0	0	0	0	0	0	441,241	[(n)] 441,241
151	Carbon Allowance Expense						0	0	0	0	0	0	(3,197,731)	[(o)] (3,197,731)
152	Umatilla Electric Cooperative	AD	EEI										500,813	[(p)] 500,813
15	TOTAL						11,790,804	0	0	0	20,707,919	748,900,419	7,742,715	777,351,053

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Represents the value of energy delivered to the PGE control area from Electricity Service Suppliers in excess of the ESS's actual load within the PGE control area.

(b) Concept: StatisticalClassificationCode

The Douglas County contract expires on 12/31/2025

(c) Concept: StatisticalClassificationCode

The Okanogan County contract expires on 12/31/2025

(d) Concept: StatisticalClassificationCode

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

(e) Concept: StatisticalClassificationCode

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

(f) Concept: StatisticalClassificationCode

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

(g) Concept: StatisticalClassificationCode

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

(h) Concept: StatisticalClassificationCode

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

(i) Concept: SettlementOfPower

Consists of expenses related to the purchase of RECs and development of future renewable resources for PGEs Portfolio Options programs. Such expenses are fully offset by customer revenues.

(j) Concept: SettlementOfPower

2021 NVPC MONET QF Deferrals & Cure Payments

(k) Concept: SettlementOfPower

Margin on electric financial transactions.

(l) Concept: SettlementOfPower

Pelton Round Butte Financial Lease amortization and interest

(m) Concept: SettlementOfPower

2021 PCAM Deferral

(n) Concept: SettlementOfPower

Expense of annual REC retirement to meet RPS compliance.

(o) Concept: SettlementOfPower

Expense of carbon allowances retired to comply with California's Cap-and-Trade Program.

(p) Concept: SettlementOfPower

2021 invoice written off in 2023.

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	BPA Power Business Line	Bonneville Power Administration	West Oregon Electric Coop Total	OLF	72	BPAT.PGE	Various	0	15,400	15,372	0	0	(ap)149,377	149,377

2	BPA Power Business Line	Bonneville Power Administration	Other TVI Pumps Total	OLF	72	BPAT.PGE	Various	0	7,424	7,410	0	0	[aq]44,900	44,900
3	BPA Power Business Line	Bonneville Power Administration	Canby PUD Total	OLF	72	BPAT.PGE	Various	0	200,025	199,653	0	0	[ar]442,806	442,806
4	BPA Power Business Line	Bonneville Power Administration	Columbia River PUD Total	OLF	72	BPAT.PGE	Various	0	202,762	202,385	0	0	[as]18,197	18,197
5	Pacificorp West	PacifiCorp	Portland General Electric	OLF	Exchange	PACW.PGE	Various	0	2,180	3,199	0	0	[at]225,872	225,872
6	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	192	118,618	118,618	179,032	[ak](265,310)	[au]76,436	(9,842)
7	Avangrid Renewables, LLC			[c] OS	11			0	0	0	0	121,306	0	121,306
8	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO	7	BPAT.PGE	Various Subs	173	87,336	87,336	161,910	[al](27,810)	[av]68,872	202,972
9	BPA Power Business Line			[d] OS	11			0	0	0	0	94,622	0	94,622
10	Calpine Energy Services	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	2,571	1,820,208	1,820,208	2,395,236	[am](4,274,092)	[aw]1,023,531	(855,325)
11	Calpine Energy Services			[e] OS	11			0	0	0	0	1,823,096	0	1,823,096
12	Constellation New Energy	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	513	366,099	366,099	482,205	[an](3,313,355)	[ax]204,229	(2,626,921)
13	Constellation New Energy			[f] OS	11			0	0	0	0	370,800	0	370,800
14	Shell Energy North America	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	244	183,917	183,917	228,789	[ao](974,686)	[ay]97,138	(648,759)
15	Shell Energy North America			[g] OS	11			0	0	0	0	184,286	0	184,286
16	Avista Corp	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	1,487	1,487	0	0	[az](6,277)	(6,277)
17	Avista Corp	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	84,123	84,123	0	0	[ba](355,123)	(355,123)
18	Avista Corp	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	0	0	0	0	0	0
19	Avista Corp	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	480	480	0	0	[bb]794	794
20	Avista Corp	California Independent System Operator	Bonneville Power Administration	[h] OS	8	Malin500	JohnDay	0	18,934	18,934	0	0	0	0
21	Avista Corp			[i] OS	11			0	0	0	0	87,343	0	87,343
22	Brookfield Renewable Trading and Marketing	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	642	642	0	0	[bc]1,200	1,200
23	Brookfield Renewable Trading and Marketing			[j] OS	11			0	0	0	0	220	0	220
24	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	257,858	257,858	0	0	[bd]842,079	842,079
25	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH	0	400	400	0	0	[be]1,306	1,306
26	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	626,537	626,537	0	0	[bf]2,046,064	2,046,064
27	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	352	352	0	0	[bg]1,150	1,150
28	Shell Energy North America	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE	0	51	51	0	0	[bh]115	115
29	Shell Energy North America	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	594	594	0	0	[bi]1,345	1,345
30	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	2,601	2,601	0	0	[bj]5,888	5,888

31	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	8,921	8,921	0	0	(bk)20,194	20,194
32	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,712	1,712	0	0	(bl)3,875	3,875
33	Shell Energy North America	Balancing Authority of Northern California	Bonneville Power Administration	(k) OS	8	CaptainJack	JohnDay	0	1,546	1,546	0	0	0	0
34	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	(l) OS	8	Malin500	JohnDay		4,955	4,955	0	0	0	0
35	Shell Energy North America			(m) OS	11			0	0	0	0	922,846	0	922,846
36	Dynasty Power Inc	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	225	225	0	0	(bm)6,321	6,321
37	Dynasty Power Inc	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	30	30	0	0	(bn)843	843
38	Dynasty Power Inc	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	857	857	0	0	(bo)24,077	24,077
39	Dynasty Power Inc	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	821	821	0	0	(bp)23,066	23,066
40	Dynasty Power Inc			(n) OS	11			0	0	0	0	2,233	0	2,233
41	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	2,234	2,234	0	0	(bq)18,996	18,996
42	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	14,763	14,763	0	0	(br)125,534	125,534
43	Constellation New Energy			(o) OS	11			0	0	0	0	13,090	0	13,090
44	Mag Energy Solutions	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	260	260	0	0	(bs)781	781
45	Mag Energy Solutions			(p) OS	11			0	0	0	0	290	0	290
46	Macquarie Energy LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	2,034	2,034	0	0	(bt)9,102	9,102
47	Macquarie Energy LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	25	25	0	0	(bu)112	112
48	Macquarie Energy LLC			(q) OS	11			0	0	0	0	5,475	0	5,475
49	Mercuria Energy America, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	3,500	3,500	0	0	(bv)5,460	5,460
50	Mercuria Energy America, LLC			(r) OS	11			0	0	0	0	3,957	0	3,957
51	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	6,090	6,090	0	0	(bw)19,559	19,559
52	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	38,912	38,912	0	0	(bx)124,971	124,971
53	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	80	80	0	0	(by)193	193
54	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	5,832	5,832	0	0	(bz)14,098	14,098
55	Morgan Stanley Capital Group	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,763	1,763	0	0	(ca)4,262	4,262
56	Morgan Stanley Capital Group			(s) OS	11			0	0	0	0	50,455	0	50,455
57	Pacificorp West	Portland General Electric	Bonneville Power Administration	LFP	7	RoundButte	REDMOND	0	13,949	13,949	0	0	(cb)178,968	178,968
58	Pacificorp West	Portland General Electric	Bonneville Power Administration	NF	8	RoundButte	REDMOND	0	444	444	0	0	(cc)5,108	5,108
59	Pacificorp West			(t) OS	11			0	0	0	0	10,065	0	10,065

60	Avangrid Renewables, LLC	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	41,358	41,358	0	0	[cd]596,861	596,861
61	Avangrid Renewables, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	40	40	0	0	[ce]217	217
62	Avangrid Renewables, LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,317	1,317	0	0	[cf]7,129	7,129
63	Avangrid Renewables, LLC			[u] OS	11			0	0	0	0	45,496	0	45,496
64	Puget Sound Energy	Portland General Electric	Bonneville Power Administration	NF	8	PGE	BPAT.PGE	0	0	0	0	0	[cg]83	83
65	Puget Sound Energy			[v] OS	11			0	0	0	0	0	0	0
66	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	9,761	9,761	0	0	[ch]60,402	60,402
67	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	647,095	647,095	0	0	[ci]4,004,308	4,004,308
68	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	1,783	1,783	0	0	[cj]11,033	11,033
69	Powerex Inc.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	1,864	1,864	0	0	[ck]3,654	3,654
70	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	553	553	0	0	[cl]1,084	1,084
71	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	501,092	501,092	0	0	[cm]982,412	982,412
72	Powerex Inc.	Balancing Authority of Northern California	Bonneville Power Administration	[w] OS	8	CaptainJack	JohnDay	0	1,282	1,282	0	0	0	0
73	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	[x] OS	8	Malin500	JohnDay	0	21,128	21,128	0	0	0	0
74	Powerex Inc.			[y] OS	11			0	0	0	0	1,115,458	0	1,115,458
75	Rainbow Energy Marketing Corp	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	736	736	0	0	[cn]1,826	1,826
76	Rainbow Energy Marketing Corp	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	9,160	9,160	0	0	[co]41,142	41,142
77	Rainbow Energy Marketing Corp	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	3,181	3,181	0	0	[cp]14,288	14,288
78	Rainbow Energy Marketing Corp			[z] OS	11			0	0	0	0	16,791	0	16,791
79	Southern California Edison	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	40	40	0	0	[cq]66	66
80	Southern California Edison			[aa] OS	11			0	0	0	0	45	0	45
81	Sacramento Municipal Utility Dist.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	5,231	5,231	0	0	[cr]9,003	9,003
82	Sacramento Municipal Utility Dist.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	406	406	0	0	[cs]699	699
83	Sacramento Municipal Utility Dist.			[ab] OS	11			0	0	0	0	4,929	0	4,929
84	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	24,703	24,703	0	0	[ct]26,198	26,198
85	The Energy Authority	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	111,577	111,577	0	0	[cu]118,331	118,331
86	The Energy Authority	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	0	0	0	0	0	0
87	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	3,345	3,345	0	0	[cv]7,007	7,007
88	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	3,822	3,822	0	0	[cw]8,006	8,006

89	The Energy Authority	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	56,829	56,829	0	0	[cx]119,048	119,048
90	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	21,265	21,265	0	0	[cy]44,547	44,547
91	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	[ac] OS	8	CaptainJack	JohnDay	0	324	324	0	0	0	0
92	The Energy Authority	Bonneville Power Administration	California Independent System Operator	[ad] OS	8	JohnDay	Malin500	0	0	0	0	0	0	0
93	The Energy Authority	California Independent System Operator	Bonneville Power Administration	[ae] OS	8	Malin500	JohnDay	0	1,725	1,725	0	0	0	0
94	The Energy Authority			[af] OS	11			0	0	0	0	232,283	0	232,283
95	Transalta Energy Marketing (US) Inc.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	12	12	0	0	[cz]44	44
96	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	176	176	0	0	[da]645	645
97	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	1,282	1,282	0	0	[db]4,697	4,697
98	Transalta Energy Marketing (US) Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,544	1,544	0	0	[dc]5,657	5,657
99	Transalta Energy Marketing (US) Inc.			[ag] OS	11			0	0	0	0	5,017	0	5,017
100	Turlock Irrigation Dist	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	30,277	30,277	0	0	[dd]51,452	51,452
101	Turlock Irrigation Dist			[ah] OS	11			0	0	0	0	21,326	0	21,326
102	Tacoma Power	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	32	32	0	0	[de]57	57
103	Tacoma Power	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	22	22	0	0	[df]39	39
104	Tacoma Power			[ai] OS	11			0	0	0	0	49	0	49
105	Vitol Inc	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	530	530	0	0	[dg]19,888	19,888
106	Vitol Inc	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	40,677	40,677	0	0	[dh]1,526,412	1,526,412
107	Vitol Inc	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	7,335	7,335	0	0	[di]13,617	13,617
108	Vitol Inc	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	203	203	0	0	[dj]377	377
109	Vitol Inc			[aj] OS	11			0	0	0	0	47,758	0	47,758
110	Public Utility District No. 1 of Cowlitz County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH	0	0	0	0	0	[dk]144,530	144,530
111	Public Utility District No. 1 of Franklin County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH	0	0	0	0	0	[dl]144,530	144,530
112	Public Utility District No. 1 of Klickitat County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH	0	0	0	0	0	[dm]158,983	158,983
113	Public Utility District No. 1 of Lewis County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH	0	0	0	0	0	[dn]158,983	158,983
114	[a] Deferral			OS									(8,472,254)	(8,472,254)
115	[b] Accrual			OS								(979,714)	1,832,825	853,111
35	TOTAL							3,693	5,658,688	5,658,916	3,447,172	(4,655,731)	7,123,245	5,914,686

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority
Incremental revenues are deferred according to OPUC OrderNo. 22-129.
(b) Concept: PaymentByCompanyOrPublicAuthority
Represents the difference between actual transmission revenue for the quarter, as reflected on the individual line items within this schedule,and the accruals credited during the quarter to FERC Account 456.1, Revenues From Transmission of Electricity for Others.
(c) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(d) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(e) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(f) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(g) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(h) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(i) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(j) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(k) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(l) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(m) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(n) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(o) Concept: StatisticalClassificationCode
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(p) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(q) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(r) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(s) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(t) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(u) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(v) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(w) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(x) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(y) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

(z) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(aa) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(ab) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(ac) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ad) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ae) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(af) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(ag) Concept: StatisticalClassificationCode
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(ah) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(ai) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(aj) Concept: StatisticalClassificationCode
(ak) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(al) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(am) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(an) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(ao) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(ap) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.
(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.
(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.
(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.
(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and PacifiCorp concerning the exchange of transmission services over agreed-upon facilities.
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes: Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.
(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes:

Scheduling, system control and dispatch service.

Reactive supply and voltage control service.

Regulation and frequency response service.

Operating reserve - spinning reserve service.

Operating reserve - supplemental reserve service.

(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes:

Scheduling, system control and dispatch service.

Reactive supply and voltage control service.

Regulation and frequency response service.

Operating reserve - spinning reserve service.

Operating reserve - supplemental reserve service.

(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes:

Scheduling, system control and dispatch service.

Reactive supply and voltage control service.

Regulation and frequency response service.

Operating reserve - spinning reserve service.

Operating reserve - supplemental reserve service.

(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes:

Scheduling, system control and dispatch service.

Reactive supply and voltage control service.

Regulation and frequency response service.

Operating reserve - spinning reserve service.

Operating reserve - supplemental reserve service.

(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(br) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(cn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(dl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(dm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Bonneville Power Admin	[a] LFP			79,870,496			79,870,496
2	Bonneville Power Admin	OS	355,135	355,135			[d] 17,969,797	17,969,797
3	Bonneville Power Admin	SFP	25,762	25,762		1,794,022		1,794,022
4	Bonneville Power Admin	NF	75,530	75,530		626,854		626,854
5	Arizona Public Service	NF	1	1		361		361
6	Avista Corp	NF	41,829	41,829		300,583		300,583
7	ALBERTA ELECTRIC SYSTEM OPERATOR	NF	315	315		2,113		2,113
8	Columbia River PUD	SFP	13	13		19,843		19,843
9	Eugene Water & Electric Board	[b] LFP	12	12		113,400		113,400
10	Idaho Power Co	NF	34,278	34,278		255,563		255,563
11	LA Dept of Water & Power	NF	2,569	2,569		28,924		28,924
12	McMinnville Water & Light	[c] LFP	895	895		10,847		10,847
13	Montana, State of	OS					[e] 1,031,648	1,031,648
14	MATL LLP	NF	595	595		5,376		5,376
15	Nextera Energy Capital Holdings Inc	OS					[f] 1,696,901	1,696,901
16	Nevada Power Company	NF	33,066	33,066		190,393		190,393
17	PacifiCorp Linneman Substation	OS					[g] 256,365	256,365
18	PacifiCorp	SFP	296,499	296,499		112,893		112,893
19	Puget Sound Energy	NF	63,565	63,565		133,175		133,175
20	WESTERN AREA POWER	NF	877	877		3,987		3,987
21	Salt River Project	NF	2,626	2,626		18,343		18,343
22	Seattle City Light	NF	2,609	2,609		4,408		4,408
23	UMATILLA ELECTRIC COOPERATIVE	OS					[h] 56,972	56,972
24	NorthWestern Energy	NF	486,940	486,940		1,400,029		1,400,029
	TOTAL		1,423,116	1,423,116	79,870,496	5,021,114	21,011,683	105,903,293

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode	
Represents Bonneville Power Administration PTP contracts that have termination dates that range from 1/1/2023 - 1/1/2030.	
(b) Concept: StatisticalClassificationCode	
Represents Eugene Water & Electric Board contract which terminates on 12/31/2028.	
(c) Concept: StatisticalClassificationCode	
Represents McMinnville Water & Light contract which terminates on 12/31/2030.	
(d) Concept: OtherChargesTransmissionOfElectricityByOthers	
Represents Bonneville Power Administration Ancillary Transmission Services	
(e) Concept: OtherChargesTransmissionOfElectricityByOthers	
Represents Beneficial Use Tax and Wholesale Energy Transaction Tax payments to the State of Montana for use of BPA's transmission lines.	
(f) Concept: OtherChargesTransmissionOfElectricityByOthers	
Represents reserve charges for Wheatridge II.	
(g) Concept: OtherChargesTransmissionOfElectricityByOthers	
Represents PacifiCorp's Linneman Transmission Services.	
(h) Concept: OtherChargesTransmissionOfElectricityByOthers	
Represents 2023 Annual Capacity Payment.	

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,651,580
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,457,218
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,137,590
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Involuntary Severance	1,738,403
7	Directors Pension	173,871
8	DIRECTORS FEES & EXPS	836,716
9	DIRECTORS & OFFICERS EXPENSES	2,261,402
10	MISC ADMIN EXPENSES	319,403
11	COLSTRIP - PPL MONTANA	731,076
46	TOTAL	14,307,259

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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.

Line No.	A. Summary of Depreciation and Amortization Charges					
	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			65,864,461		65,864,461
2	Steam Production Plant	35,007,741	2,673,347			37,681,088
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	27,648,236	68			27,648,304
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	88,558,829	956,786			89,515,615
7	Transmission Plant	24,763,185				24,763,185
8	Distribution Plant	137,175,623	5,513			137,181,136
9	Regional Transmission and Market Operation					
10	General Plant	48,387,011	115			48,387,126
11	Common Plant-Electric					
12	TOTAL	361,540,625	3,635,829	65,864,461		431,040,915

B. Basis for Amortization Charges

Five year and ten year amortization of computer software. Five, twenty-five, and thirty year amortization of permits. Thirty, forty and fifty year amortization of hydro licensing costs.

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	Depreciation parameters per Order 21-463 in OPUC Docket UM- 2152. Rates effective as of 5/9/2022. Certain energy storage asset depreciation parameters per Order 18-290 in OPUC Docket UM-1856.						

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

REGULATORY COMMISSION EXPENSES

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

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

												(l)
1	FERC:											
2	FERC matters less than $25,0000		143,374	143,374				143,374				
3	OPUC:											
4	OPUC Docket UE 394		492,548	492,548				492,548				
5	OPUC Docket UE 412		41,106	41,106				41,106				
6	OPUC Docket UE 416		191,457	191,457				191,457				
7	OPUC Docket UM 2299		69,683	69,683				69,683				
8	OPUC Docket UM 1931		27,978	27,978				27,978				
9	OPUC Docket AR 631		79,658	79,658				79,658				
10	OPUC Docket UM 2111		87,541	87,541				87,541				
11	OPUC Docket UM 2032		29,420	29,420				29,420				
12	OPUC Docket LC 80		50,252	50,252				50,252				
13	OPUC Docket UM 1728		22,078	22,078				22,078				
14	OPUC matters less than $25,0000		275,138	275,138				275,138				
15	Unassigned Non-Doc Matters		481,580	481,580				481,580				
46	TOTAL	0	1,991,813	1,991,813	0			1,991,813	0		0	0

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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(6)	Electric R, D & D Performed Internally - Other	840		930.2	840	
2	B(1)	Electric R, D & D Performed Externally		2,429,069	930.2	2,422,706	
3	B(4)	Electric R, D & D Performed Externally		84,028	930.2	84,028	

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	36,440,864		
4	Transmission	12,365,306		
5	Regional Market			
6	Distribution	52,988,898		
7	Customer Accounts	23,089,534		
8	Customer Service and Informational	9,069,965		
9	Sales			
10	Administrative and General	91,428,537		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	225,383,104		
12	Maintenance			
13	Production	9,498,762		
14	Transmission	1,045,337		
15	Regional Market			
16	Distribution	28,703,384		
17	Administrative and General	1,506,221		
18	TOTAL Maintenance (Total of lines 13 thru 17)	40,753,704		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	45,939,626		
21	Transmission (Enter Total of lines 4 and 14)	13,410,643		
22	Regional Market (Enter Total of Lines 5 and 15)			

23	Distribution (Enter Total of lines 6 and 16)	81,692,282		
24	Customer Accounts (Transcribe from line 7)	23,089,534		
25	Customer Service and Informational (Transcribe from line 8)	9,069,965		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	92,934,758		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	266,136,808	21,388,097	287,524,905
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
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			0
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	266,136,808	21,388,097	287,524,905
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	85,226,900	32,554,235	117,781,135
69	Gas Plant			0
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	85,226,900	32,554,235	117,781,135
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,079,193	80,667	2,159,860
74	Gas Plant			0
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,079,193	80,667	2,159,860
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,943,847	95,738	2,039,585
79	Co-Owner Shares of Generating Facilities	5,916,387	560,811	6,477,198
80	Other	8,095,811	371,845	8,467,656
81	Payroll Allocated	55,051,393	(55,051,393)	0
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	71,007,438	(54,022,999)	16,984,439
96	TOTAL SALARIES AND WAGES	424,450,339	0	424,450,339

FERC FORM NO. 1 (ED. 12-88)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line	Description of Item(s)	Balance at End of Quarter 1	Balance at End of Quarter 2	Balance at End of Quarter 3	Balance at End of Year

No.	(a)	(b)	(c)	(d)	(e)
1	Energy				
2	Net Purchases (Account 555)	15,301,568	12,808,169	16,956,102	[a]52,755,763
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	17,133,564	11,448,414	14,079,778	[b]60,399,238
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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43					
44					
45					
46	TOTAL	32,435,132	24,256,583	31,035,880	113,155,001

FERC FORM NO. 1 (NEW. 12-05)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

Represents purchases with ISO, netted by settlement invoice period and market.

(b) Concept: IsoOrRtoSettlementsEnergyNetSales

Represents sales with ISO, netted by settlement invoice period and market.

FERC FORM NO. 1 (NEW. 12-05)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	355,135	MWH	16,122,820	1,738,584	MWH	960,986
2	Reactive Supply and Voltage				4,253	MWH	147,613
3	Regulation and Frequency Response				3,693	MWH	321,420
4	Energy Imbalance	[(a)]193,364	MWH	[(b)]10,158,750	[(c)]23,033	MWH	[(d)]1,386,792
5	Operating Reserve - Spinning				[(e)]3,693	MW	370,870
6	Operating Reserve - Supplement				[(f)]3,693	MW	370,870
7	Other						
8	Total (Lines 1 thru 7)	548,499		26,281,570	1,776,949		3,558,551

FERC FORM NO. 1 (New 2-04)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
The Energy Imbalance Number of Units is based on difference of each transmission customer's hourly base schedule less their actual hourly energy usage by retail customers. Over scheduled amounts represent actual energy usage less than their scheduled amount. PGE purchases the over scheduled energy quantity from the transmission customers.
(b) Concept: AncillaryServicesPurchasedAmount
The Amount Purchased for the Energy Imbalance Dollars amount is based on the CAISO OASIS published hourly LMP prices for the PGE ELAP in the Western EIM market multiplied by their over scheduled amount.
(c) Concept: AncillaryServicesSoldNumberOfUnits
The Energy Imbalance Number of Units is based on difference of each transmission customer's hourly base schedule less their actual hourly energy usage by retail customers. Under scheduled amounts represent actual energy usage greater than their scheduled amount. PGE sells the under scheduled energy quantity to the transmission customers.
(d) Concept: AncillaryServicesSoldAmount
The Amount Purchased for the Energy Imbalance Dollars amount is based on the CAISO OASIS published hourly LMP prices for the PGE ELAP in the Western EIM market multiplied by their under scheduled amount.
(e) Concept: AncillaryServicesSoldNumberOfUnits
The Number of Units value represents the hourly peak scheduled value for each transmission customer at the monthly system peak, summed over the 12 months of the year per the OATT schedule formula.
(f) Concept: AncillaryServicesSoldNumberOfUnits
The Number of Units value represents the hourly peak scheduled value for each transmission customer at the monthly system peak, summed over the 12 months of the year per the OATT schedule formula.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: PGE									
1	January	4,723	18	18	2,942	288	2,561	53	2,402	205
2	February	4,948	23	19	3,395	278	2,561	75	2,402	98
3	March	4,524	13	20	2,828	296	2,561	74	2,402	42
4	Total for Quarter 1				9,165	862	7,683	202	7,206	345
5	April	4,144	5	20	2,561	281	2,561	66	2,402	600
6	May	4,652	14	20	3,043	286	2,561	70	2,402	141
7	June	4,843	12	19	3,174	328	2,561	88	2,302	485
8	Total for Quarter 2				8,778	895	7,683	224	7,106	1,226
9	July	5,497	16	19	3,312	300	2,561	79	3,152	238
10	August	6,120	14	17	4,102	350	2,561	93	3,577	48
11	September	4,853	15	18	3,158	313	2,561	78	3,202	530
12	Total for Quarter 3				10,572	963	7,683	250	9,931	816
13	October	4,116	20	20	2,260	270	2,561	58	3,102	604
14	November	4,624	29	8	3,143	292	2,561	88	3,148	54
15	December	4,609	7	18	2,902	283	2,561	68	3,498	228
16	Total for Quarter 4				8,305	845	7,683	214	9,748	886
17	Total				36,820	3,565	30,732	890	33,991	3,273

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report

Portland General Electric Company	(1) An Original (2) A Resubmission	2024-04-18	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)	19,131,728
3	Steam	2,213,634	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,803,299
5	Hydro-Conventional	1,144,387	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	29,505
7	Other	[(a)] 12,876,003	27	Total Energy Losses	1,060,068
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	16,234,024	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	28,024,600
10	Purchases (other than for Energy Storage)	11,790,804			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	5,658,688			
17	Delivered	5,658,916			
18	Net Transmission for Other (Line 16 minus line 17)	(228)			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	28,024,600			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2024-04-18	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherEnergyGeneration

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, Coyote Springs, and Carty generation plants (as shown on page 403), and generation from PGE's solar generation facilities (as shown on page 410), other generation includes 1,883,016 megawatt hours of net wind energy from PGE's Biglow Canyon Wind Farm, Tucannon River Wind Farm and Wheatridge Wind Farm. Actual gross wind generation from the wind farms was 1,891,784 megawatt hours.

The Biglow Canyon Wind Farm was placed in service in three phases between December 2007 and August 2010. Key statistics include the following:

In-service production cost at 12/31/2023: $955,833,932

Total installed capacity: 450 megawatts

Operations and maintenance expense for 2023: $14,254,683

The Tucannon River Wind Farm was placed in service in December, 2014. Key statistics include the following:

In-service production cost at 12/31/2023: $498,126,676

Total installed capacity: 267 megawatts

Operations and maintenance expense for 2023: $9,145,056

The Wheatridge Wind Farm was placed in service in December, 2020. Key statistics include the following:

In-service production cost at 12/31/2023: $147,437,264

Total installed capacity: 100 megawatts

Operations and maintenance expense for 2023: $3,381,785

FERC FORM NO. 1 (ED. 12-90)

Page 401a

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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: PGE					
29	January	2,312,802	460,946	3,661	30	8
30	February	2,245,091	536,575	3,656	23	19
31	March	2,371,016	573,570	3,344	8	9
32	April	2,068,574	489,421	3,180	3	9
33	May	2,095,752	557,972	3,581	17	19
34	June	2,228,218	692,574	3,509	12	19
35	July	2,675,200	941,708	3,902	19	19
36	August	2,714,010	885,044	4,498	16	19
37	September	2,426,524	953,876	3,458	15	18
38	October	2,257,345	678,241	3,075	30	9
39	November	2,156,939	496,128	3,450	29	18
40	December	2,473,357	694,148	3,209	18	18
41	Total	28,024,828	7,960,203			

FERC FORM NO. 1 (ED. 12-90)

Page 401b

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: Beaver	Plant Name: Carty	Plant Name: [a] Colstrip	Plant Name: Coyote Springs	Plant Name: Port Westward 1	Plant Name: Port Westward 2
							Reciprocating

1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas & Steam Turbine	Gas & Steam Turbine	Steam	Gas & Steam Turbine	Gas & Steam Turbine	Engine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Outdoor		Outdoor	Outdoor	Outdoor
3	Year Originally Constructed	1974	2016		1995	2007	2014
4	Year Last Unit was Installed	2001	2016		1995	2007	2014
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	570.4	503.1	311.2	296	483.3	225.1
6	Net Peak Demand on Plant - MW (60 minutes)	519	473		276	408	214
7	Plant Hours Connected to Load	7,151	7,275		7,858	8,177	7,990
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	533			270	421	225
10	When Limited by Condenser Water						
11	Average Number of Employees	41	30		31	31	
12	Net Generation, Exclusive of Plant Use - kWh	1,722,258,000	3,095,654,000	2,213,634,000	1,928,414,000	3,063,127,000	1,172,195,000
13	Cost of Plant: Land and Land Rights	24,473		3,328,862		24,473	
14	Structures and Improvements	38,127,989	95,635,579	116,300,825	11,611,128	43,220,414	42,471,958
15	Equipment Costs	287,105,747	437,394,780	379,724,023	194,298,387	245,591,643	263,451,562
16	Asset Retirement Costs	2,941,318	10,434,861	34,911,263	113,193	231,072	647,461
17	Total cost (total 13 thru 20)	328,199,527	543,465,220	534,264,973	206,022,708	289,067,602	306,570,981
18	Cost per KW of Installed Capacity (line 17/5) Including	575.3849	1,080.233	1,716.7898	696.0227	598.1121	1,361.9324
19	Production Expenses: Oper, Supv, & Engr	499,206	283,401	(184,198)	704,323	685,672	82,261
20	Fuel	116,207,707	68,860,563	48,621,978	39,731,934	190,554,390	67,324,854
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses			1,833,604			
23	Steam From Other Sources						
24	Steam Transferred (Cr)						
25	Electric Expenses	3,666,793	4,433,709		2,747,027	4,011,603	2,830,688
26	Misc Steam (or Nuclear) Power Expenses	1,707,480	1,447,346	3,330,183	1,495,531	1,289,291	438,247
27	Rents	217,035		0	87,122	28,586	33,347
28	Allowances				0	0	0
29	Maintenance Supervision and Engineering	1,204,448	481,414	361,016	185,452	391,663	99,729
30	Maintenance of Structures	114,138	49,431	989,089	98,619	77,307	38,360
31	Maintenance of Boiler (or reactor) Plant		0	7,928,015			
32	Maintenance of Electric Plant	6,727,041	11,880,575	707,045	4,261,610	5,859,529	3,881,828
33	Maintenance of Misc Steam (or Nuclear) Plant	180,341	167,835	678,423	79,475	151,456	194,419
34	Total Production Expenses	130,524,189	87,604,274	64,265,155	49,391,093	203,049,497	74,923,733
35	Expenses per Net kWh	0.0758	0.0283	0.029	0.0256	0.0663	0.0639

35	**Plant Name**	Beaver	Beaver	Carty	Coyote Springs	Port Westward 1	Port Westward 2
36	Fuel Kind	Gas	Oil	Gas	Gas	Gas	Gas
37	Fuel Unit	Mcf's	Barrels	Mcf's	Mcf's	Mcf's	Mcf's
38	Quantity (Units) of Fuel Burned	16,809,961	0	21,006,084	13,790,799	20,818,986	9,870,833
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,019,000	138,690	1,019,000	1,019,000	1,019,000	1,019,000

40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	9.175	182.7	2.391	2.426	8.846	7.044
41	Average Cost of Fuel per Unit Burned	6.913	0	3.278	2.881	9.153	6.821
42	Average Cost of Fuel Burned per Million BTU	6.782	0	3.216	2.826	8.979	6.691
43	Average Cost of Fuel Burned per kWh Net Gen	0.067	0	0.022	0.021	0.062	0.057
44	Average BTU per kWh Net Generation	[(b)]9,949.459	[(c)]0	6,917.094	7,289.876	6,928.282	8,583.905

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Jointly owned. Talen Montana, LLC is the joint owner/operator of the plant. Reported herein is respondents 20 percent share of installed capacity, cost of plant, net generation and production expenses of Units 3 & 4.

(b) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

(c) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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. 2195 Plant Name: Faraday	FERC Licensed Project No. 2195 Plant Name: North Fork	FERC Licensed Project No. 2195 Plant Name: Oak Grove	FERC Licensed Project No. 2030 Plant Name: [(a)] Pelton	FERC Licensed Project No. 2030 Plant Name: [(b)] Pelton (PGE%)	FERC Licensed Project No. 2195 Plant Name: River Mill	FERC Licensed Project No. 2030 Plant Name: [(c)] Round Butte	FERC Licensed Project No. 2030 Plant Name: [(d)] Round Butte (PGE%)	FERC Licensed Project No. 2233 Plant Name: Sullivan
1	Kind of Plant (Run-of-River or Storage)	Run-of River;Storage	Run-of River	Run-of River	Storage	Storage	Run-of River	Storage	Storage	Run-of River
2	Plant Construction type (Conventional or Outdoor)	Conventional; Outdoor	Outdoor	Conventional	Outdoor	Outdoor	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1907	1958	1924	1957	1957	1911	1964	1964	1895
4	Year Last Unit was Installed	2023	1958	1931	1958	1958	1952	1964	1964	1953
5	Total installed cap (Gen name plate Rating in MW)	50	62.1	51	109.8	54.9	20.7	372.5	186.3	16.9
6	Net Peak Demand on Plant-Megawatts (60 minutes)	44	56	39	105		26	245		18
7	Plant Hours Connect to Load	8,366	7,480	8,671	8,657		8,745	8,754		7,679
8	**Net Plant Capability (in megawatts)**									
9	(a) Under Most Favorable Oper Conditions	46	56	43	114		25	373		18
10	(b) Under the Most Adverse Oper Conditions	5	7	19	60		4	192		7
11	Average Number of Employees	52		1	[(e)]			[(f)]42		1

12	Net Generation, Exclusive of Plant Use - kWh	92,966,000	154,167,000	151,188,000	345,994,801	173,032,000	85,546,000	788,636,273	394,397,000	93,091,000
13	**Cost of Plant**									
14	Land and Land Rights	33,434	377,100	9,457	3,681,653	1,841,302	86,408	3,699,286	1,891,263	572,077
15	Structures and Improvements	77,679,228	9,364,422	16,848,734	10,554,676	5,302,476	7,501,595	18,801,763	9,447,633	17,950,463
16	Reservoirs, Dams, and Waterways	90,906,320	86,076,883	32,755,692	15,511,814	8,016,063	58,516,526	164,853,500	85,345,223	31,499,172
17	Equipment Costs	76,101,007	20,625,070	26,986,540	31,193,217	17,969,892	19,575,186	43,018,050	180,151,401	14,509,822
18	Roads, Railroads, and Bridges	1,990,337	2,837,601	6,767,403	6,005,214	3,082,085	475,899	2,567,432	1,380,273	
19	Asset Retirement Costs	90	6	2,122	52	52	64	164	164	2,630
20	Total cost (total 13 thru 20)	246,710,416	119,281,082	83,369,948	66,946,626	36,211,870	86,155,678	232,940,195	278,215,957	64,534,164
21	Cost per KW of Installed Capacity (line 20 / 5)	4,934.2083	1,920.7904	1,634.7049	609.7143	659.5969	4,162.11	625.3428	1,493.376	3,818.5896
22	**Production Expenses**									
23	Operation Supervision and Engineering	102,233	12,831	11,964	226,949	71,465	17,097	466,703	276,667	563
24	Water for Power	84,211	66,181	69,009	228,218	89,490	54,764	388,573	219,017	45,346
25	Hydraulic Expenses	1,689,393	596,202	1,599,985	2,620,638	1,356,212	537,070	3,002,009	1,456,600	274,947
26	Electric Expenses	959,093	250,252	244,830	466,418	247,806	68,414	508,679	241,486	54,551
27	Misc Hydraulic Power Generation Expenses	1,432,146	366,555	375,160	735,775	385,143	145,450	823,224	394,674	223,121
28	Rents	195,116	120,916	843,011	15,777	4,367		34,946	21,000	
29	Maintenance Supervision and Engineering	492,442	2,992	33,294	4,843	2,404	1,406	6,000	3,019	2,597
30	Maintenance of Structures									
31	Maintenance of Reservoirs, Dams, and Waterways	42,785	162,090	229,231	101,572	30,608	19,083	213,889	127,155	297,691
32	Maintenance of Electric Plant	195,107	48,004	286,425	261,359	109,231	181,591	413,404	227,469	115,100
33	Maintenance of Misc Hydraulic Plant	908,685	280,483	415,205	199,057	73,913	42,881	361,240	208,286	99,060
34	Total Production Expenses (total 23 thru 33)	6,101,211	1,906,506	4,108,114	4,860,606	2,370,639	1,067,756	6,218,667	3,175,373	1,112,976
35	Expenses per net kWh	0.0656	0.0124	0.0272	0.014	0.0137	0.0125	0.0079	0.0081	0.012

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Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Portland General Electric Company	(1) An Original (2) A Resubmission	04/18/2024	End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Respondent is the principal owner (50.01% interest) and operator of the plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon. Reported here are 100% costs and plant statistics, including shared and non-shared costs.

(b) Concept: PlantName

Jointly owned. Reported here are respondents 50.01% share of installed capacity, cost of plant, net generation and production expenses.

(c) Concept: PlantName

Respondent is the principal owner (50.01% interest) and operator of the plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon. Reported here are 100% costs and plant statistics, including shared and non-shared costs.

(d) Concept: PlantName

Jointly owned. Reported here are respondents 50.01% share of installed capacity, cost of plant, net generation and production expenses.

(e) Concept: PlantAverageNumberOfEmployees

Pelton employees are reported at the Round Butte Location. Pelton and Round Butte are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.

(f) Concept: PlantAverageNumberOfEmployees

Pelton employees are reported at the Round Butte Location. Pelton and Round Butte are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Oregon Military Dept/Anderson Readiness Center	2001	1.6	1.6	50	192,125	120,078		2,810	28,664	diesel-low	2,144	Other
2	US Bank Corp Columbia Center	2001	6.4	6.2	74	488,057	76,259			51,679	diesel-low	2,324	Other
3	Portland State University	2004	2.8	2.8	26	261,802	93,501		27,300	54,541	diesel-low	2,587	Other
4	Oregon Military Joint Forces HQ	2005	1.6	1.6	9	191,439	119,649			44,610	diesel-low	2,324	Other
5	Stimson Lumber	2005	0.57	0.51	5	159,546	279,905			16,060	diesel-low	2,324	Other
6	Flexential (Formerly ViaWest/Fortix)	2005	14	12.4	136	629,125	44,938		24,658	99,656	diesel-low	2,190	Other
7	Skyline	2005	2	1.8	60	201,526	100,763		15,307	97,616	diesel-low	2,354	Other
8	NCCWC Filter Plant	2005	2	1.8	45	122,958	61,479		12,174	61,969	diesel-low	2,209	Other
9	PCC Structurals	2005	1	0.9	8	113,874	113,874		755	7,983	diesel-low	2,178	Other
10	Providence Portland Medical Center	2005	6	5.4	96	265,383	44,231		29,771	67,800	diesel-low	2,379	Other
11	Salem Hospital	2006	8	7.2	106	269,108	33,639		55,303	147,121	diesel-low	2,107	Other
12	Sunrise Water Authority Pump Station	2006	1.25	1.13	5	832,919	666,335		1,938	16,210	diesel-low	2,325	Other
13	Providence Newberg Hospital	2006	1.5	1.35	14	156,833	104,555		7,105	22,641	diesel-low	2,213	Other
14	H5 (Formerly vXchnge/Sungard DSG)	2006	2	1.8	9	331,845	165,923			15,016	diesel-low	2,324	Other
15	Kaiser Sunnyside Hospital	2007	4.5	4.05	107	352,752	78,389			57,195	diesel-low	2,324	Other
16	Newberg Waste Water Treatment Plant	2008	2	1.8	61	760,722	380,361		17,530	30,634	diesel-low	2,533	Other
17	Xerox Corp	2007	4	3.6	30	384,805	96,201		7,130	31,402	diesel-low	2,513	Other
18	Newberg Water Treatment Plant	2007	1	0.9	14	86,545	86,545		3,165	51,669	diesel-low	2,535	Other
19	Oregon Dept of Admin Serv - Data Center	2010	3.86	3.47	25	332,026	86,017			60,699	diesel-low	2,324	Other

20	Amazon (Formerly Panasonic/Sanyo)	2010	1	0.9	17	621,108	621,108		3,778	5,995	diesel-low	2,271	Other
21	Sysco Foods	2010	2	1.8	44	193,165	96,583		6,636	12,417	diesel-low	2,225	Other
22	Clackamas Intertie 2	2012	0.6	0.54	15	704,498	1,174,163		3,057	29,152	diesel-low	2,357	Other
23	Dawson Creek	2012	0.8	0.72	5	104,092	130,115			17,680	diesel-low	2,324	Other
24	Kaiser Westside Hospital	2012	4	3.6	56	408,830	102,208		22,911	27,047	diesel-low	2,056	Other
25	North Plains Pump Station	2012	0.8	0.72	9	61,517	76,896			17,828	diesel-low	2,324	Other
26	Oak Lodge Sanitary District	2012	2	1.8	46	237,530	118,765		6,401	19,579	diesel-low	2,293	Other
27	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.5	1.25	9	284,255	189,503			48,825	diesel-low	2,324	Other
28	Oregon State Hospital	2012	4	3.6	62	172,879	43,220		39,114	97,598	diesel-low	2,582	Other
29	Portland Service Center	2012	0.5	0.45	12	331,241	662,482			4,152	diesel-low	2,324	Other
30	Sandy Highschool	2012	1.25	1.13	27	188,279	150,623		5,668	12,059	diesel-low	2,251	Other
31	TATA Communications - Hillsboro	2012	4.5	4.05	20	328,979	73,106			51,078	diesel-low	2,324	Other
32	Tri-City Wastewater Treatment Plant	2012	2.5	2.25	63	170,080	68,032		15,233	25,082	diesel-low	2,362	Other
33	TATA Communications - Portland	2013	6	5.4	32	612,983	102,164			47,076	diesel-low	2,324	Other
34	City of Hillsboro Crandall Reservoir	2013	0.8	0.72	5	114,239	142,799			12,494	diesel-low	2,324	Other
35	East County Courts	2013	1.5	1.35	14	316,848	211,232		4,409	23,479	diesel-low	2,643	Other
36	City of Portland-Columbia Blvd WWTP	2013	1	0.9	24	170,620	170,620		6,378	29,578	diesel-low	2,335	Other
37	US Foods (Formerly Food Services of America)	2013	2	1.8	31	1,026,301	513,151		7,459	21,454	diesel-low	2,278	Other
38	Avery DSG	2014	0.8	0.72	20	263,782	329,728			22,671	diesel-low	2,324	Other
39	Carver (Readiness Center) DSG	2014	2	1.8	49	818,635	409,318		22,772	52,198	diesel-low	2,710	Other
40	Juvenile Justice Center	2014	0.75	0.68	13	171,531	228,708			11,176	diesel-low	2,324	Other
41	Clackamas River Water	2014	2	1.8	31	1,095,503	547,752		7,815	51,102	diesel-low	2,265	Other
42	Joint Water Commission	2015	5	4.5	114	198,688	39,738		26,834	25,955	diesel-low	2,213	Other
43	McLane Foodservice	2016	1.5	1.35	36	1,085,278	723,519		7,457	14,242	diesel-low	2,483	Other
44	Flexential Brookwood (Formerly ViaWest Brookwood)	2016	16.25	14.63	1,614	582,945	35,874		99,651	133,120	diesel-low	2,353	Other
45	World Trade Center	2017	3.2	2.88	27	1,021,168	319,115		3,777	40,971	diesel-low	2,233	Other
46	Washington County Jail	2017	1.5	1.35	15	325,578	217,052		12,452	16,051	diesel-low	2,243	Other
47	OHSU - Vaccine Gene Therapy Institute	2017	1.5	1.25	8	366,768	244,512			42,726	diesel-low	2,324	Other
48	OHSU - Center for Health & Healing	2018	3	2.7	34	351,605	117,202			30,168	diesel-	2,324	Other

											low		
49	OHSU - Knight Cancer Research Building	2018	2	1.8	17	237,298	118,649		4,306	16,155	diesel-low	2,155	Other
50	Hattan Road Pump Station - HRPS	2021	1	0.9	1	212,306	212,306		1,696	12,688	diesel-low	2,324	Other
51	Beaverton Public Service Center	2021	1	0.9		523,446	523,446			36,469	diesel-low	2,324	Other
52	Kellogg Creek WWTP	2022	1.5	1.35	32	277,521	185,014		10,022	39,826	diesel-low	2,284	Other
53	Solar	2012	3.02	3.02	2,306	1,324,428	438,698	29,314		14,802	solar		Solar

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Beaverton Public Safety Center	Distribution	Beaverton, OR	1,178,477	0	0	0	0	0
2	Port Westward 2	Production	Clatskanie, OR	6,332,259	0	0	0	0	0
3	Anderson Readiness Center	Distribution	Salem, OR	1,658,159	0	0	0	0	0
4	Salem Smart Grid Battery	Distribution	Salem, OR	384,933	0	23,540	0	0	0
36	TOTAL			9,553,828	0	23,540	0	0	0

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	500KV LINES											0				0
2	[a] BOARDMAN	GRASSLAND	500	500	ST. TOWER	0.94		1	2-1780 ACSR			0				0
3	[b] BROADVIEW SWITCHYARD	TOWNSEND 'A'	500	500	ST. TOWER	133.4		1				0				0
4	[c] BROADVIEW SWITCHYARD	TOWNSEND 'B'	500	500	ST. TOWER	133.4		1				0				0
5	CARTY	GRASSLAND	500	500	ST. TOWER	0.75		1	2-1780 ACSR			0				0
6	[d] COLSTRIP SWITCHYARD	BROADVIEW 'A'	500	500	ST. TOWER	112.7		1				0				0
7	[e] COLSTRIP SWITCHYARD	BROADVIEW 'B'	500	500	ST. TOWER	115.9		1				0				0
8	[f] COYOTE SPRINGS	SLATT BPA	500	500								0				0
9	GRASSLAND	SLATT BPA	500	500	ST. TOWER	16.73		1	2-1780 ACSR			0				0
10	GRIZZLY BPA	MALIN BPA #2	500	500	ST. TOWER	178.5		1	2-1780 ACSR			0				0
11	GRIZZLY BPA	ROUND BUTTE	500	500	ST. TOWER	15.6		1	2-1780 ACSR			0				0
12	[g] JOHN DAY	GRIZZLY '1'	500	500				1				0				0
13	[h] JOHN DAY	GRIZZLY '2'	500	500				1				0				0
14	TOTAL 500KV LINES									1,526,610	86,639,716	88,166,326	2,694,077	826,802	2,433,773	5,954,652
15	230 KV LINES											0				0
16	BEAVER	PORT WESTWARD	230	230	H-WOOD	0.41		1	2156 ACSS			0				0
17	BETHEL	McLOUGHLIN	230	230	H-WOOD	35.52		1	1272 AAC			0				0
18	BETHEL	ROUND BUTTE	230	230	H-WOOD/ST. TOWER	98.68		1	1272 AAC			0				0
19	BETHEL	SANTIAM BPA	230	230	H-WOOD	3.64		1	795 ACSR			0				0
20	[i] BIG EDDY BPA	McLOUGHLIN	230	230	H-WOOD	0.91		1	1780 ACSR			0				0
21	[j] BIGLOW CANYON WF	JOHN DAY #1 BPA	230	230				1	2388 AAC TW			0				0
22	BLUE LAKE	GRESHAM	230	230	ST. TOWER	5.92		2	1272 ACSS			0				0
23	BLUE LAKE	TROUTDALE BPA #1	230	230	ST. MONOP/ST. TOWER	1.45		1	1272 ACSS			0				0
24	BLUE LAKE	TROUTDALE BPA #2	230	230	ST. MONOP/ST. TOWER	0.15	1.34	2	1272 ACSS			0				0
25	[k]	SHERWOOD	230	230	ST. TOWER	8.95		2	1272 AAC			0				0

	CARLTON BPA															
26	CARVER	GRESHAM #1	230	230	H-WOOD	7.33		1	1272 AAC			0				0
27	CARVER	McLOUGHLIN #1	230	230	H-WOOD/ST. MONOP	4.87		1	1272 AAC			0				0
28	CARVER	McLOUGHLIN #2	230	230	ST. MONOP		4.88	1	1272 ACSS			0				0
29	CENTRAL FERRY BPA	MULLAN (TUCANNON WF)	230	230	H-WOOD	20.62		1	954 ACSR			0				0
30	DALREED PACW	(q) CARTY	230	230	H-WOOD	16.76		1	795 AAC			0				0
31	(l) GRESHAM	TROUTDALE PACW #1	230	230	H-WOOD	0.43		1	954 ACSR			0				0
32	GRESHAM	TROUTDALE PACW #2	230	230	ST. TOWER	0.33		1	1272 AAC			0				0
33	HARBORTON	RIVERGATE #1	230	230	ST. TOWER/H-WOOD	1.7		1	1272 AAC			0				0
34	HARBORTON	TROJAN #1	230	230	ST TOWER	33.6		2	1590 AAC			0				0
35	HORIZON	KEELER BPA	230	230	ST. MONOP	1.47		2	1272 ACSS			0				0
36	HORIZON	ST. MARYS - TROJAN	230	230	ST. TOWER/ST. MONOP	12.95	32.95	1	1590 AAC			0				0
37	(m) KEELER BPA	RIVERGATE	230	230	ST. TOWER	0.08		2	1272 AAC			0				0
38	KEELER BPA	ST. MARYS	230	230	H-WOOD/ST. TOWER	6.47		2	1590 ACSR TWD			0				0
39	McLOUGHLIN	PEARL BPA - SHERWOOD	230	230	ST. TOWER/ST. MONOP	16.38	4.7	2	2-1272 AAC/1272 AAC/2-1780 ACSR			0				0
40	MURRAYHILL	SHERWOOD #1	230	230	ST. TOWER	5.58		2	1272 AAC			0				0
41	MURRAYHILL	SHERWOOD #2	230	230	ST. TOWER		5.55	2	1272 AAC			0				0
42	MURRAYHILL	ST. MARYS	230	230	ST. TOWER	5.2		2	1272 ACSS			0				0
43	(n) PEARL BPA	SHERWOOD	230	230	ST. MONOP/ST. TOWER/H-WOOD	4.88		1	2-2388 AAC TW			0				0
44	(o) PELTON	ROUND BUTTE	230	230	H-WOOD	7.87		1	795 ACSR			0				0
45	PORT WESTWARD	TROJAN #1	230	230	H-WOOD/ST. MONOP	18.76		1	2156 ACSS			0				0
46	PORT WESTWARD	TROJAN #2	230	230	H-WOOD/ST. MONOP	9.28	9.48	2	2156 ACSS			0				0
47	REDMOND BPA	ROUND BUTTE	230	230	H-WOOD	23.81		1	795 ACSR			0				0
48	(p) RIVERGATE	ROSS BPA	230	230	ST. TOWER	0.09		2	795 ACSR			0				0
49	ROUND BUTTE	GENERATOR #1	230	230	ST. TOWER			1	795 ACSR			0				0
50	ROUND BUTTE	GENERATOR #2	230	230	ST. TOWER			1	795 ACSR			0				0
51	ROUND BUTTE	GENERATOR #3	230	230	ST. TOWER			1	795 ACSR			0				0
52	TOTAL 230KV LINES									8,602,221	142,392,099	150,994,320	1,157,250	337,756	732,744	2,227,750
53	ALL 115KV LINES					435.58						0				0
54	ALL 57KV LINES					11.81						0				0

55	TOTAL 115KV & 57KV LINES									1,309,175	234,919,992	236,229,167	224,995	62,002		286,997
36	TOTAL					1,509.4	58.9	60		11,438,006	463,951,807	475,389,813	4,076,322	1,226,560	3,166,517	8,469,399

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.

(b) Concept: TransmissionLineStartPoint

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.

(c) Concept: TransmissionLineStartPoint

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.

(d) Concept: TransmissionLineStartPoint

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.

(e) Concept: TransmissionLineStartPoint

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.

(f) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 1995 to Bonneville Power Administration. PGE recorded these costs to FERC accounts 354 Transmission Towers and Fixtures, 356 Transmission Overhead Conductors and Devices. Wire Mileage is not reported here as BPA is owner/operator of these Transmission Lines.

(g) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacity conductor on this line. PGE has certain capacity responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire mileage not reported as BPA is owner/operator of this section of Transmission Line.

(h) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacity conductor on this line. PGE has certain capacity responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire mileage not reported as BPA is owner/operator of this section of Transmission Line.

(i) Concept: TransmissionLineStartPoint

Represents ownership of one circuit on Bonneville Power Administration's double circuit line.

(j) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2007 to Bonneville Power Administration. PGE recorded the CIAC to FERC accounts 355 Transmission Poles and Fixtures, 356 Transmission Overhead Conductors and Devices. Wire mileage is not reported here as BPA is owner/operator of these transmission lines.

(k) Concept: TransmissionLineStartPoint

Represents ownership of one circuit on Bonneville Power Administration's double circuit line.

(l) Concept: TransmissionLineStartPoint

Represents contract with PacifiCorp whereby PGE is entitled to 1/2 the capacity of the line.

(m) Concept: TransmissionLineStartPoint

Represents partial ownership of one circuit on Bonneville Power Administration's line.

(n) Concept: TransmissionLineStartPoint

Represents ownership of one circuit on Bonneville Power Administration's double circuit line.

(o) Concept: TransmissionLineStartPoint

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon.Total length is indicated. Costs are respondent's share.

(p) Concept: TransmissionLineStartPoint

Represents partial ownership of one circuit on Bonneville Power Administration's line.

(q) Concept: TransmissionLineEndPoint

Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)	CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Construction (q)
1	No Additions in 2023																
44	TOTAL																

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	2 Substation Under 10 MVA capacity	Distribution	Unattended	115	13		16.8	2		Capacitor Banks	2	3.6
2	6 Substation Under 10 MVA capacity	Distribution	Unattended	57	13		44.3	8				
3	Abernethy, Oregon City, OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks	4	12
4	Alder, Portland, OR	[(ad)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
5	Amity, near Amity, OR	Distribution	Unattended	57	13		7.5	1				
6	Arleta, Portland, OR	Distribution	Unattended	57	13		47.60	2		Capacitor Banks	2	7.2
7	[(a)] Bakeoven, BPA, Near Bakeoven, OR	Transmission	Unattended	500								
8	Banks, Banks, OR	Distribution	Unattended	57	13		20	1		Capacitor Banks	2	3
9	Barnes, Salem, OR	Distribution	Unattended	115	13		42.4	2		Capacitor Banks	2	6
10	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	13		464	4				
11	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	24		170	1				
12	Beaverton, Beaverton, OR	[(ae)] Transmission	Unattended	115	13		33.6	2		Capacitor Banks	4	12
13	Bell, near Portland, OR	[(af)]	Unattended	115	13		65.8	3		Capacitor Banks	6	18

		Transmission										
14	Bethany, Portland, OR	(ag) Transmission	Unattended	115	13		56	2		Capacitor Banks	5	15
15	Bethel, Salem, OR	(ah) Transmission	Unattended	230	115	13	642	3				
16	Bethel, Salem, OR	(ai) Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
17	Biglow Canyon Windfarm	Transmission	Unattended	230	34.5	13	480	3				
18	Blue Lake, Troutdale, OR	(aj) Transmission	Unattended	230	115	13	640	2				
19	Blue Lake, Troutdale, OR	(ak) Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
20	Boones Ferry, Lake Oswego, OR	(al) Transmission	Unattended	115	13		50	2		Capacitor Banks	2	7.2
21	Boring, near Boring, OR	Distribution	Unattended	57	13		16.8	1		Capacitor Banks	1	12.15
22	(b) Broadview Subst. near Broadview, MT	Transmission	Unattended	500	230		80	3				
23	Brookwood, near Hillsboro, OR	Transmission	Unattended	115	13		100	2		Capacitor Banks	4	12
24	(c) Buckley, BPA near Buckley, WA	Transmission	Unattended	500								
25	Butler, Hillsboro OR	(am) Transmission	Unattended	115	13		300	2		Capacitor Banks	2	48
26	Canby, near Barlow, OR	Distribution	Unattended	57	13		39.3	4				
27	Canemah, Oregon City, OR	(an) Transmission	Unattended	115	57	13	264.8	4	2			
28	Canyon, Portland, OR	(ao) Transmission	Unattended	115	13		200	4		Capacitor Banks	8	28.8
29	(d) Captain Jack, BPA, Near Malin, OR	Transmission	Unattended	500								
30	Carty, near Boardman, OR	Transmission	Unattended	500	230	24	1170.5	4				
31	Carty, near Boardman, OR	Transmission	Unattended	230	7.2		55	1				
32	Carver, Carver, OR	(ap) Transmission	Unattended	230	115	13	640	2				
33	Carver, Carver, OR	(aq) Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
34	Cascade, St Helens, OR	Distribution	Unattended	115	13		46.4	2	1	Capacitor Banks	4	12
35	Cedar Hills, near Beaverton, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	13.2
36	Centennial, near Gresham, OR	Distribution	Unattended	115	13		39.2	2		Capacitor Banks	2	7.2
37	(e) Chemawa BPA, near Salem, OR	Distribution	Unattended	115								
38	(f) Chemawa BPA, near Salem, OR	Distribution	Unattended	57								
39	Clackamas, Clackamas, OR	(ar) Transmission	Unattended	115	13		43	2		Capacitor Banks	4	13.2
40	Claxtar, Salem,OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
41	Coffee Creek, Sherwood, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
42	(g) Colstrip Plant, near Colstrip, MT	Transmission	Unattended	500	26		164	3				
43	(h) Colstrip Subst. near Colstrip, MT	Transmission	Unattended	500	230		100	2				
44	Cornelius, Cornelius, OR	(as) Transmission	Unattended	57	13		28	1		Capacitor Banks	2	6
45	Cornelius, Cornelius, OR	(at) Transmission	Unattended	115	57	13	140	1	1			
46	Cornell, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6

47	[(i)] Coyote Springs, Boardman, OR	Transmission	Unattended	500			300	3				
48	Culver, Salem, OR	[(au)] Transmission	Unattended	115	13		28	1				
49	Curtis, Portland, OR	[(av)] Transmission	Unattended	115	13		16.8	1		Capacitor Banks	2	6
50	Dayton, near Dayton , OR	[(aw)] Transmission	Unattended	57	13		19.5	2		Capacitor Banks	4	6
51	Dayton, near Dayton , OR	[(ax)] Transmission	Unattended	115	57	13	125	1				
52	Delaware, Portland, OR	[(ay)] Transmission	Unattended	115	13		28	1				
53	Denny, Beaverton, OR	[(az)] Transmission	Unattended	115	13		56	2		Capacitor Banks	2	6
54	Dilley, near Forest Grove, OR	Distribution	Unattended	57	13		12.5	1		Capacitor Banks	3	9
55	Dunns Corner, near Sandy,OR	[(ba)] Transmission	Unattended	57	13		14	1		Capacitor Banks	2	3
56	Durham, Tigard , OR	Distribution	Unattended	115	13		77	4		Capacitor Banks	4	12.6
57	E., Portland, OR	[(bb)] Transmission	Unattended	115	13		202.4	5		Capacitor Banks	4	28.8
58	E., Portland, OR	[(bc)] Transmission	Unattended	115	11		132.4	4		Capacitor Banks	1	24
59	Eagle Creek, Eagle Creek, OR	Distribution	Unattended	57	13		14	1				
60	Eastport, Portland, OR	[(bd)] Transmission	Unattended	115	13		16.8	1		Capacitor Banks	2	6
61	Elma, near Salem, OR	Distribution	Unattended	57	13		56	2		Capacitor Banks	4	12
62	Estacada, Estacada, OR	Distribution	Unattended	57	13		29.6	2		Capacitor Banks	2	3.6
63	Fairmount, Salem, OR	[(be)] Transmission	Unattended	115	13		25	1		Capacitor Banks	1	3.6
64	Fairview, Fairview, OR	[(bf)] Transmission	Unattended	115	13		50.4	2		Capacitor Banks	1	3
65	Faraday Plant, near Estacada, OR	[(bg)] Transmission	Unattended	115	13		27	1				
66	Faraday, Switchyard, OR	[(bh)] Transmission	Unattended	115	57	13	140	1				
67	Faraday, Switchyard, OR	[(bi)] Transmission	Unattended	57	11		32	2				
68	[(j)] Forest Grove BPA, Forest Grove, OR	Transmission	Unattended	115								
69	[(k)] Fort Rock, 12 mi NE of Silver Lake, OR	Transmission	Unattended	500						Series Capacitor	1	363
70	Garden Home, near Portland, OR	Distribution	Unattended	115	13		28	1				
71	Glencoe, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
72	Glencullen, Portland, OR	[(bj)] Transmission	Unattended	115	13		24	1		Capacitor Banks	2	6
73	Glendoveer, near Portland, OR	[(bk)] Transmission	Unattended	115	13		50.4	2				
74	Glisan, Gresham, OR	[(bl)] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
75	Grand Ronde, Grand Ronde, OR	[(bm)] Transmission	Unattended	115	57	13	33	1	1			
76	Grand Ronde, Grand Ronde, OR	[(bn)] Transmission	Unattended	115	13		12.5	1		Capacitor Banks	2	3
77	Grassland, near Boardman, OR	Transmission	Unattended	500								
78	Gresham, near Gresham, OR	Transmission	Unattended	230	115	13	572	2				
79	[(l)] Grizzly, BPA, near Madras, OR	Transmission	Unattended	500								

80	Harborton, near Portland, OR	[bo] Transmission	Unattended	230	115	13	320	1		Capacitor Banks	1	24
81	Harborton, near Portland, OR	[bp] Transmission	Unattended	115	13		53	2		Capacitor Banks	4	12
82	Harmony, near Milwaukie, OR	Distribution	Unattended	115	13		50.4	2		Capacitor Banks	4	12
83	Harrison Sub, Portland, OR	[bq] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
84	Hayden Island, near Portland, OR	Distribution	Unattended	115	13		33.6	2		Capacitor Banks	4	12
85	Helvetia, Hillsboro, OR	[br] Transmission	Unattended	115	34.5		200	4		Capacitor Banks	8	36
86	Hemlock, Portland, Or	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
87	Hillcrest, Salem , OR	[bs] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
88	Hillsboro, Hillsboro , OR	Distribution	Unattended	57	13		43.4	2		Capacitor Banks	4	14.4
89	Hogan North, Gresham, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
90	Hogan South, Gresham, OR	[bt] Transmission	Unattended	115	57	13	125	3				
91	Hogan South, Gresham, OR	[bu] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
92	Holgate, Portland, OR	Distribution	Unattended	57	13		39.2	2		Capacitor Banks	2	7.2
93	Horizon, Hillsboro, OR	Transmission	Unattended	230	115	13	960	3				
94	Huber, near Beaverton, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	2	6
95	Indian, near Salem, OR	[bv] Transmission	Unattended	115	13		56	2		Capacitor Banks	3	10.8
96	Island, near Milwaukie, OR	[bw] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
97	Jennings Lodge, Jennings Lodge, OR	Distribution	Unattended	115	13		52.5	2				
98	[m] Keeler, BPA, Hillsboro, OR	Transmission	Unattended									
99	Kelley Point, Portland, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
100	Kelly Butte, Portland, OR	[bx] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	2	6
101	King City, near King City, OR	[by] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
102	Leland, Oregon City, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
103	Lents, near Portland, OR	Distribution	Unattended	115	13		22.4	1				
104	Lents, near Portland, OR	Distribution	Unattended	57	11		20	2				
105	Liberal	Distribution	Unattended	115	13		14	1		Capacitor Banks	1	12
106	Liberty, Salem, OR	[bz] Transmission	Unattended	115	13		50.4	2		Capacitor Banks	3	10.2
107	Main, Hillsboro, OR	Distribution	Unattended	57	13		84	3		Capacitor Banks	6	20.4
108	[n] Malin, BPA, near Malin, OR	Transmission	Unattended	500						Reactors	3	180
109	Market, Salem, OR	[ca] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
110	Marquam, Portland OR	[cb] Transmission	Unattended	115	13		250	5		Capacitor Banks	10	54
111	McClain, Salem, OR	Distribution	Unattended	57	13		22.5	3				
112	McGill, Gresham, OR	[cc] Transmission	Unattended	115	13		75.4	3		Capacitor Banks	6	18
113	McLoughlin, near Oregon City, OR	[cd] Transmission	Unattended	230	115	13	640	2				
114	Meridian, near Tualatin, OR	[ce] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18

115	Middle Grove, near Middle Grove, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
116	Midway, near Portland, OR	Distribution	Unattended	115	13		33.6	2		Capacitor Banks	1	3.6
117	Mill Creek, near Salem, OR	(cf) Transmission	Unattended	115	13		16.8	1		Capacitor Banks	2	6
118	Mobile No. 1, OR	Distribution	Unattended	115	57	13	25	1				
119	Mobile No. 2, OR	Distribution	Unattended	115	57	13	34	1				
120	Mobile No. 3, OR	Distribution	Unattended	115	57	13	29	1				
121	Mobile No. 4, OR	Distribution	Unattended	115	57	13	34	1				
122	Mobile No. 5, OR	Distribution	Unattended	115	57	13	34	1				
123	Mobile No. 6, OR	Distribution	Unattended	115	57	13	34	1				
124	Mobile No. 7, OR	Distribution	Unattended	115	57	13	25	1				
125	Mobile No. 8, OR	Distribution	Unattended	115	57	13	25	1				
126	Molalla, Molalla, OR	Distribution	Unattended	57	13		42.4	2		Capacitor Banks	4	9
127	Monitor, near Monitor, OR	(cg) Transmission	Unattended	230	57	13	125	1	2			
128	Mt. Angel, Mt. Angel, OR	Distribution	Unattended	57	13		20	1		Capacitor Banks	3	15
129	Mt. Pleasant, Oregon City , OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks		
130	Multnomah, Portland, OR	Distribution	Unattended	115	13		39.2	2		Capacitor Banks	3	9
131	Murrayhill, Beaverton, OR	(ch) Transmission	Unattended	115	13		56	2		Capacitor Banks	3	10.8
132	Murrayhill, Beaverton, OR	(ci) Transmission	Unattended	230	115	13	320	1				
133	Newberg, Newberg, OR	(cj) Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
134	North Fork, near Estacada, OR	Transmission	Unattended	115	13	0.48	53	3				
135	North Marion, near Woodburn, OR	Distribution	Unattended	57	13		30.875	3		Capacitor Banks	3	15
136	North Plains, North Plains, OR	Distribution	Unattended	57	13		20	1		Capacitor Banks	4	16.5
137	Northern, Portland, OR	Transmission	Unattended	115	13		28	1				
138	Oak Grove, Three Lynx, OR	(ck) Transmission	Unattended	115	13		8	1				
139	Oak Grove, Three Lynx, OR	(cl) Transmission	Unattended	115	11		64	2				
140	Oak Grove, Three Lynx, OR	(cm) Transmission	Unattended	13	11							
141	Oak Grove, Three Lynx, OR	(cn) Transmission	Unattended	13	0.48							
142	Oak Hills, near Beaverton, OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks	4	14.4
143	(o) Oregon City - BPA, Wilsonville, OR	Distribution	Unattended	57								
144	Orenco, near Hillsboro, OR	(co) Transmission	Unattended	115	57	13	280	2	1			
145	Orenco, near Hillsboro, OR	(cp) Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
146	Orient, near Gresham, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
147	Oswego, Lake Oswego, OR	(cq) Transmission	Unattended	115	13		33.6	2		Capacitor Banks	2	7.2
148	Oxford, Salem, OR	(cr) Transmission	Unattended	115	13		50.4	2		Capacitor Banks	4	12.3
149	(p) Pearl, BPA, near Wilsonville, OR	Transmission	Unattended	230								
150	(q)	Transmission	Unattended	230	13		120	3				

	Pelton, near Madras , OR											
151	[r] Pelton, near Madras, OR	Transmission	Unattended	13	13		3	1				
152	Peninsula Park, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
153	Pleasant Valley, near Portland, OR	[cs] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
154	Port Westward, near Clatskanie, OR	Transmission	Unattended	230	18		900	3				
155	Port Westward, near Clatskanie, OR	Transmission	Unattended	13	4.2		40	2				
156	Portsmouth, Portland, OR	[ct] Transmission	Unattended	115	13		28	1				
157	Progress, near Tigard, OR	[cu] Transmission	Unattended	115	13		50	2		Capacitor Banks	4	13.8
158	Raleigh Hills, near Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6.6
159	Ramapo, near Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
160	Redland, near Oregon City, OR	Distribution	Unattended	115	13		22.4	1				
161	Reedville, near Beaverton, OR	[cv] Transmission	Unattended	115	13		84	3	4	Capacitor Banks	6	20.4
162	[s] Rhododendron Switching, OR	Distribution	Unattended	57								
163	River Mill, near Estacada, OR	[cw] Transmission	Unattended	57	11		32	2				
164	Rivergate North Yard, Portland, OR	[cx] Transmission	Unattended	230	115	13	520	4	1	Capacitor Banks	1	24
165	Rivergate South Yard, Portland, OR	[cy] Transmission	Unattended	115	13		22.4	1		Capacitor Banks	2	7.2
166	Rivergate South Yard, Portland, OR	[cz] Transmission	Unattended	115	11		22.4	1		Capacitor Banks	2	6.716
167	Riverview, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
168	Rock Creek, near Portland, OR	[da] Transmission	Unattended	115	113		28	1		Capacitor Banks	2	6
169	Rockwood, near Gresham, OR	Distribution	Unattended	115	13		78.4	3		Capacitor Banks	5	15
170	Rosemont, near Lake Oswego, OR	[db] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
171	Roseway, Hillsboro, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
172	[t] Round Butte, near Madras, OR	[dc] Transmission	Unattended	500	230	13	570	4		Reactors	4	60
173	[u] Round Butte, near Madras, OR	[dd] Transmission	Unattended	230	13		394	4				
174	Ruby, Gresham, OR	[de] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
175	Salem-PGE, near Salem, OR	Distribution	Unattended	57	13		44.8	2		Capacitor Banks	4	12
176	[v] Sand Springs, South of Bend, OR	Transmission	Unattended	500						Series Capacitor	1	546
177	Sandy, Sandy, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
178	[w] Scappoose, Scappoose, OR	[df] Transmission	Unattended	115								
179	Scholls Ferry, Beaverton, OR	[dg] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
180	Scoggins, near Gaston, OR	Distribution	Unattended	57	13		13	2		Capacitor Banks	1	10.8
181	Sellwood, Portland, OR	[dh] Transmission	Unattended	115	57	13	140	1		Capacitor Banks	1	24
182	Sellwood, Portland, OR	[di] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
183	Sheridan, Sheridan, OR	Distribution	Unattended	57	13		16.8	1		Capacitor Banks	3	15.6

184	Sherwood, near Six Corners, OR	Transmission	Unattended	230	115	13	640	2				
185	Shute, Hillsboro, OR	[dj] Transmission	Unattended	115	34.5		400	4	2	Capacitor Banks	8	36
186	Silverton, Silverton, OR	Distribution	Unattended	57	13		42	2				
187	Six Corners, Six Corners, OR	[dk] Transmission	Unattended	115	13		49	2		Capacitor Banks	4	12
188	[x] Slatt, BPA, Arlington, OR	Transmission	Unattended	500								
189	Springbrook, Newberg, OR	[dl] Transmission	Unattended	115	13		56	2		Capacitor Banks	5	36
190	[y] St. Helens, near St. Helens, OR	[dm] Transmission	Unattended	115						Capacitor Banks	1	24
191	St. Louis, Gervais, OR	Distribution	Unattended	57	13		23.5	2		Capacitor Banks	2	7.2
192	St. Marys, East Yard, Beaverton, OR	[dn] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
193	St. Marys, West Yard, Beaverton, OR	[do] Transmission	Unattended	230	115	13	960	3		Capacitor Banks	3	108
194	Sullivan, West Linn, OR	[dp] Transmission	Unattended	57	4.15		33	1				
195	Sullivan, West Linn, OR	[dq] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
196	Summit, Government Camp, OR	Distribution	Unattended	57	13		8.4	1				
197	Summit, Government Camp, OR	Distribution	Unattended	24	13		14	1				
198	Sunset, near Hillsboro, OR	[dr] Transmission	Unattended	115	13		400	8		Capacitor Banks	8	43.2
199	Sunset, near Hillsboro, OR	[ds] Transmission	Unattended	115	34.5		375	3		Capacitor Banks	5	45.6
200	Swan Island, Portland, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
201	[z] Sycan, 27 mi S of Silver Lake, OR	Transmission	Unattended	500						Series Capacitor	1	546
202	Sylvan, near Portland, OR	Distribution	Unattended	115	13		22.4	1		Capacitor Banks	2	4.8
203	[aa] Tabor, Portland, OR	[dt] Transmission	Unattended	57								
204	Tabor, Portland, OR	[du] Transmission	Unattended	115	13		22.4	1		Capacitor Banks	2	6
205	Tektronix, Beaverton, OR	[dv] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
206	Temp A, OR	Distribution	Unattended	115	57	13	20	1				
207	Temp C, OR	Distribution	Unattended	115	57	13	28	1				
208	Temp G, OR	Distribution	Unattended	115	57	13	28	1				
209	Temp H, OR	Distribution	Unattended	115	11		21	1				
210	Tigard, Tigard, OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks	4	12
211	Town Center, Portland, OR	[dw] Transmission	Unattended	115	13		56	2		Capacitor Banks	2	6
212	Trojan, near Rainier, OR	[dx] Transmission	Unattended	230	13		56	2				
213	[ab] Troutdale, BPA near Troutdale OR	Transmission	Unattended	230								
214	Tualatin, Tualatin, OR	[dy] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	14.4
215	Tucannon Mullan Switchyard, Tucannon Dayton, Wa	Transmission	Unattended	230	34.5	13	320	2		Capacitors/reactors	6	90
216	Twilight, Canby, OR	Distribution	Unattended	57	13		28	1	1	Capacitor Banks	3	19.2
217	University, Salem, OR	[dz] Transmission	Unattended	115	13		22.4	1		Capacitor Banks	2	7.2

218	Urban, Portland, OR	[(ea)] Transmission	Unattended	115	13		106.4	4		Capacitor Banks	5	39.6
219	Wacker, Portland, OR	[(eb)] Transmission	Unattended	115	13		56	2		Capacitor Banks	2	6
220	Waconda, near Hopmere, OR	Distribution	Unattended	57	13		40.6	2		Capacitor Banks	3	18
221	Wallace, Salem, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
222	Welches, near Welches, OR	Distribution	Unattended	57	24		10	1	1	Capacitor Banks	1	12
223	Welches, near Welches, OR	Distribution	Unattended	57	13		18	2		Capacitor Banks	2	6
224	[(ac)] West Portland, Lower Yard, Tigard, OR	[(ec)] Transmission	Unattended	115						Capacitor Banks	1	24
225	West Portland, Upper Yard, Tigard, OR	[(ed)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	14.4
226	West Union, near Hillsboro, OR	[(ee)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
227	Willamina, near Willamina, OR	Distribution	Unattended	57	13		30.8	2		Capacitor Banks	3	7.8
228	Willbridge, Portland, OR	Distribution	Unattended	115	11		28	1				
229	Wilsonville, near Wilsonville, OR	[(ef)] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
230	Woodburn, Woodburn, OR	Distribution	Unattended	57	13		42	2		Capacitor Banks	4	13.2
231	Yamhill, near Yamhill, OR	Distribution	Unattended	57	13		15.3	2		Capacitor Banks	1	1.8
232	Distribution Substations			7,939	1,607	143	2,876.075	143	3		165	574.05
233	Distribution Substations Unattended			7,939	1,607	143	2,876.075	143	3		165	574.05
234	Transmission Substations			24,091	4,160.53	323.48	19,406.5	256	14		286	3,036.42
235	Transmission Substations Unattended			24,091	4,160.53	323.48	19,406.5	256	14		286	3,036.42
236	Total						22,282.575					

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.

(b) Concept: SubstationNameAndLocation

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 16% share of the jointly owned capacity. 100% of the capacity is reported.

(c) Concept: SubstationNameAndLocation

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.

(d) Concept: SubstationNameAndLocation

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.

(e) Concept: SubstationNameAndLocation

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

(f) Concept: SubstationNameAndLocation

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

(g) Concept: SubstationNameAndLocation

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of the jointly owned capacity. 100% of the capacity is reported.

(h) Concept: SubstationNameAndLocation

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 14% share of the jointly owned capacity. 100% of the capacity is reported.

(i) Concept: SubstationNameAndLocation

Contribution in aid of construction made to Bonneville Power Administration in 1995 and 2006 to FERC account 353.

(j) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(k) Concept: SubstationNameAndLocation
Line compensation only.
(l) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(m) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(n) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(o) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(p) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(q) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(r) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(s) Concept: SubstationNameAndLocation
Switching only.
(t) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(u) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(v) Concept: SubstationNameAndLocation
Line compensation only.
(w) Concept: SubstationNameAndLocation
Switching only. Distribution owned by Columbia River PUD.
(x) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(y) Concept: SubstationNameAndLocation
Switching only. Distribution owned by Columbia River PUD.
(z) Concept: SubstationNameAndLocation
Line compensation only.
(aa) Concept: SubstationNameAndLocation
Switching only.
(ab) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(ac) Concept: SubstationNameAndLocation
Switching only.
(ad) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
(ae) Concept: SubstationCharacterDescription
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(af) Concept: SubstationCharacterDescription
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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/18/2024	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	Lease Payments for Corporate Headquarters at WTC	121 SW Salmon Street Corp	418	7,454,507
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative Services	121 SW Salmon Street Corp	Various	2,478,882

42				

FERC FORM NO. 1 ((NEW))