e-FILING REPORT COVER SHEET

COMPANY NAME: Portland General Electric

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ■ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ■ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ■ Yes, report docket number: RE 54

Report is required by: ■ OAR 860-027-0070
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ■ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

PGE's 2023 FERC Form 1; PGE's 2023 Oregon Supp to FERC Form 1; and PGE's 2023 Annual Report to Shareholders

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

May 1, 2024

Via Electronic Mail

Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

RE: RE 54 PGE's 2023 Annual Report and 2023 FERC Form 1

Dear Filing Center,

Enclosed for filing are PGE's 2023 Annual Report, and 2023 FERC Form 1. This includes:

- PGE's 2022 FERC Form 1 and
- PGE's 2022 Annual Report

Not included are five printed copies of PGE's 2023 Annual Report. PGE provides this information to Shareholders in electronic format only. The link to the Annual Report is provided below.

http://investors.portlandgeneral.com/financial-information/annual-reports

If you have any questions or require further information, please call me at 503-464-7488. Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Jaki Ferchland
Jaki Ferchland
Manager, Revenue Requirement

JF/dm
cc: Bryan Conway, OPUC

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.

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

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".

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		

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

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

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

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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

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			

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

Page 103

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

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

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

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	As of December 31, 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	As of December 31, 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):

<u>Years ending December 31:</u>	
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.

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

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.

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

Page 122-123

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)		

FERC FORM No. 1 (NEW 06-02)

Page 122 (a)(b)

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.

FERC FORM No. 1 (NEW 06-02)

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

FERC FORM No. 1 (REV. 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: 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.

FERC FORM No. 1 (REV. 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

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				
30				
31				
32				
33				
34				
35				
36				
37				
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41				
42				
43				
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).

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

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		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	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													

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)

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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

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												

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

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

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.

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

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

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

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

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

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

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

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: 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)**

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 Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR: Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED: Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
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 Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	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

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

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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**

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)

Page 300-301

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

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

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

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).

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.
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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	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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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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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 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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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)
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41	TOTAL Billed Sales To Railroads and Railways					
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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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					

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

Page 304

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)
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)			

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	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

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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 FOR RESALE (Account 447)

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

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER 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.

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		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	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.
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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

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(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bq) 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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(ca) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(da) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(dc) 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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: 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.						

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

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		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
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	

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

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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

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)

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					
10					
11					
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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

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

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.

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

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

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

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

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

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

FERC FORM NO. 1 (NEW 12-12)

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)

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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: 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)

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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

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	(q)
1	No Additions in 2023																
44	TOTAL																

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

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	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

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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					

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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: 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

The substation has a mix of both transmission and distribution assets.

(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))

2023 ANNUAL REPORT

Advancing toward a clean energy future

PURPOSE:

We exist to power the advancement of society

We energize lives, strengthen communities and foster energy solutions that promote social, economic and environmental progress.

VISION:

To lead the clean energy future

Together, with our customers, stakeholders, and communities, we will lead the energy transformation by **decarbonizing, electrifying and performing.**

VALUES:

We serve

We put our customers at the center of everything we do. We listen, empathize, and respond with creativity and urgency.

We innovate

We contribute to a world in motion by pursuing continuous and proactive innovation. We question what isn't working, take calculated risks, and drive the change we wish to see in the world.

We connect

We care about one another, our local communities, and this beautiful landscape we call home. We act as a good neighbor and do the right thing.

We sustain

We build long-term value that is good for people and our planet. We operate responsibly, doing more with less impact.

Letter from our CEO

TO OUR SHAREHOLDERS

Portland General Electric's (PGE) business strategy is grounded in the values that reflect our purpose and progress as a company, as we work towards the goals we hold in common with the customers and communities we serve. In 2023, PGE made important progress to invest in grid resilience and reduce risk, while continuing to deliver on our foundational responsibility to customers–providing safe, reliable, affordable energy.

Our 2023 net income, based on generally accepted accounting principles (GAAP) was $228 million, or $2.33 per diluted share. Non-GAAP net income was $233, or $2.38[1] per diluted share. These financial results were lower than expected, as we faced power market volatility and challenging weather conditions throughout the year. PGE navigated a new peak for summer demand during a triple-digit August heatwave, as well as one of our area's warmest Decembers on record and low wind and hydropower production.

We remain confident in our trajectory for long-term growth. In 2023, PGE demonstrated our commitment to operational excellence and strong execution on cost management, as our teams streamlined work processes, leveraged technology and improved productivity. PGE also successfully advanced innovation and upgraded our customer and financial systems to increase efficiency, improve customer experiences and strengthen our digital foundation for business growth. The registration of a $300 million at-the-market program and the establishment of a successful production tax credit sale program built on our late-2022 $500 million equity issuance.

In addition, the 2024 General Rate Case included important risk reductions for power cost management during extreme weather events. Agreements for 475 MW of battery storage, combined with new hydropower contracts, enhanced grid reliability, and the Clearwater wind farm has brought 311 MW of clean energy online. PGE and our partners were awarded eight federal grants totaling $314 million. PGE also invested over $1.4 billion in capital to address customer growth, improve resilience and reliability, and invest in grid modernization and security.

PGE continued to attract and retain a diverse workforce, with women accounting for 35% and Black, Indigenous, and People of Color (BIPOC) employees accounting for more than 27% of the leadership at our company. We graduated the fourth cohort of our Accelerate and Illuminate leadership development programs designed to expand leadership diversity and creating new career pathways for women and BIPOC employees.

PGE's business practices and priorities for 2024 align with our core values, as we continue to work toward a clean energy future. I am excited for the work ahead to execute our strategic plan to provide value for customers, communities, and shareholders.

Maria Pope
President & CEO

1. See the Financial Highlights page for important information about non-GAAP measures and reconciliations

Powering the Advancement of Society

PGE LEADS THE WAY

Our mission is to power the advancement of society and deliver a smarter, cleaner future for Oregon. Together with our customers, communities, and partners, we are creating a safe, reliable, clean energy future. We aim to lead the energy transformation by decarbonizing the grid, electrifying the economy from transportation to homes and buildings, and in operating our business to remain cost effective and financially healthy. Executing on our Decarbonize, Electrify and Perform strategy requires a focus and commitment to affordability, grid reliability and equitable outcomes for all customers.

Decarbonize

System flexibility through clean energy investment
Entered into agreements to procure 475 MW of battery storage– the largest single procurement by a U.S. utility outside the state of California. Battery energy storage facilities allow PGE to optimize the renewable power in its portfolio and enable integration of more intermittent clean energy resources, like wind and solar.

35%

PGE's percentage of total system load served from non-emitting energy sources.

275MW

PGE's battery storage ownership at the Constable and Seaside projects, which are projected to come online in 2024 and 2025, respectively.

#1

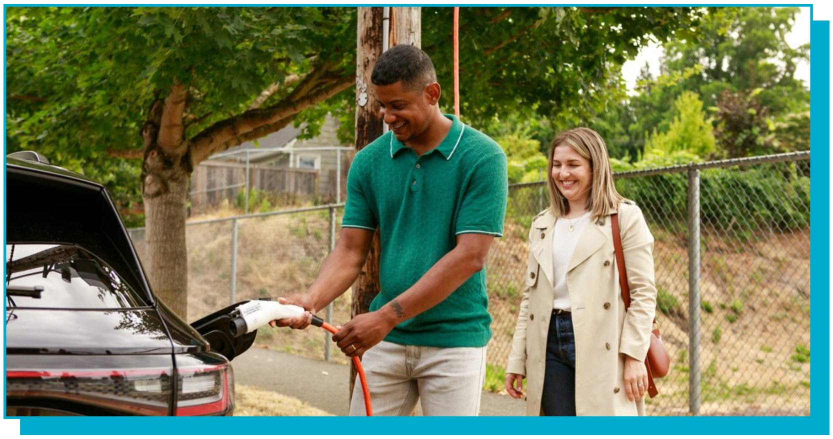
For the 14th year[1], PGE has held the U.S. Department of Energy's National Renewable Energy Laboratory's No. 1 ranking for the largest participation of business and residential renewable energy customers in a renewables program of any U.S. electric utility.

500MW

Hydropower contracts executed to improve capacity portfolio and resource adequacy.

—
1. NREL did not release rankings in 2011

Electrify



Top 5

Ranked as a Top 5 Utility in the United States for Customer Experience for 3 consecutive years (2021–2023).

4th

Oregon ranks as the fourth largest retail market for EVs.

Access and Electrification

Installed the first EV pole chargers as part of the Municipal Charging Collaboration Pilots to improve EV charger accessibility and support underserved communities.

Charging Onward

PGE's Drive Change Fund helped Oregon's first all-electric garbage truck complete its first pickup in downtown Portland. PGE's Fleet Partner program also helped install necessary charging infrastructure.

Perform

$1.4B

Invested over $1.4 billion in capital assets, to address decarbonization, customer demand growth, grid resiliency and security, and risk mitigation.

$314M

Awarded 8 grants totaling $314 million, in conjunction with partners, for critical transmission upgrades, smart grid technology, energy workforce development, transportation electrification, cybersecurity, and emergency readiness.

64%

Decrease in safety incidents

OSHA recordable safety incidents decreased by 64% over the past 5 years.

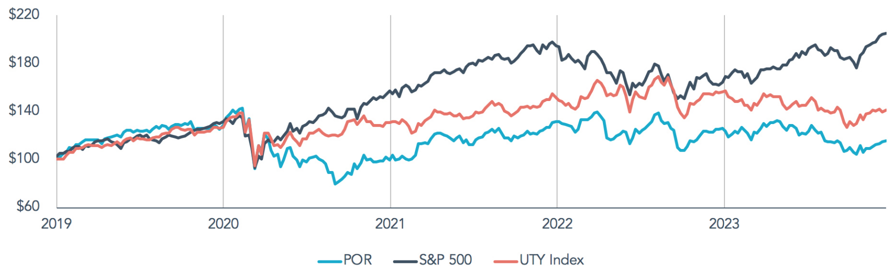
Financial Highlights

ABOUT PGE

Portland General Electric Company, headquartered in Portland, Oregon, is an integrated energy company that generates, transmits and distributes electricity to over 930,000 customers serving an area of 1.9 million Oregonians. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

Dollars in millions, except per-share amounts	2023	2022	2021	2020	2019
Total revenues	$2,923	$2,647	$2,396	$2,145	$2,123
Income from operations	$396	$397	$378	$269	$353
Net income	$228[3]	$233	$244	$155	$214
Earnings per share, diluted	$2.33[3]	$2.60	$2.72	$1.72	$2.39
Return on average equity	7.5%	8.5%	9.2%	6.0%	8.4%
Total assets	$11,208	$10,459	$9,494	$9,069	$8,394
Dividends paid per common share	$1.86	$1.77	$1.68	$1.56	$1.50
Weighted-average shares outstanding (in thousands), diluted	97,952	89,643	89,627	89,645	89,559
Average number of customers throughout the year	929,000	922,000	912,000	902,000	890,000
Common equity ratio[1]	44.6%	43.3%	45.2%	45.0%	49.9%
Senior secured debt ratings (S&P/Moody's)	A/A1	A/A1	A/A1	A/A1	A/A1
Employees	2,842	2,873	2,839	2,870	2,949

STOCK PERFORMANCE[2]

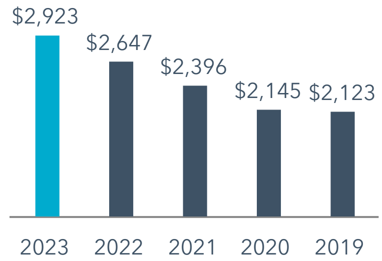


1. Excludes lease obligations
2. The chart above assumes a $100 investment in Portland General Electric's common stock and each index on Dec. 31, 2018, and that all dividends were reinvested
3. Non-GAAP net income and diluted earnings per share excluding the effects of the Boardman revenue requirement settlement charge was $233 million and $2.38, respectively. PGE believes that excluding the effects of this item provides a meaningful representation of the Company's comparative earnings per share and enables investors to evaluate the Company's ongoing operating financial performance. Management utilizes non-GAAP measures to assess the Company's current and forecasted performance, and for communications with shareholders, analysts and investors. PGE's reconciliation of non-GAAP earnings for the year ended December 31, 2023 is below.

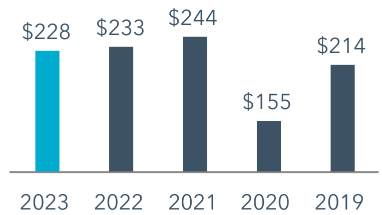
Non-GAAP Earnings Reconciliation for the year ended December 31, 2023		
(Dollars in millions, except EPS)	Net Income	Diluted EPS
GAAP as reported for the year ended December 31, 2023	$228	$2.33
Exclusion of Boardman revenue requirement settlement charge	7	0.07
Tax effect[a]	(2)	(0.02)
Non-GAAP as reported for the year ended December 31, 2023	$233	$2.38

a. Tax effects were determined based on the Company's full-year blended federal and state statutory tax rate

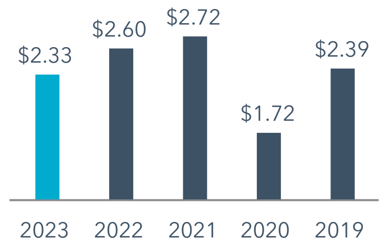
Total Revenue (dollars in millions)



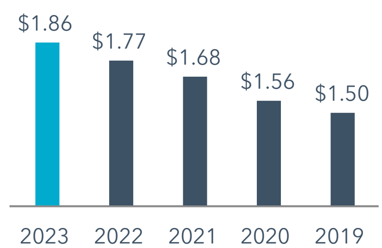
Net Income (dollars in millions)



Diluted Earnings per Share



Long Term Dividend Growth



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2023

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from ______ to ______

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 S.W. Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

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

(Title of class)	(Trading symbol)	(Name of exchange on which registered)
Common Stock, no par value	POR	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2023, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $4,609,106,568. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 8, 2024, there were 101,162,366 shares of common stock outstanding.

<u>Documents Incorporated by Reference</u>

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on April 19, 2024.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2023

TABLE OF CONTENTS

DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

Abbreviation or Acronym	Definition
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
BESS	Battery Energy Storage System
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
Carty	Carty natural gas-fired generating plant
Clearwater	PGE owned portion of the Clearwater Wind Development in Eastern Montana
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
EIM	Energy Imbalance Market
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
GRC	General Rate Case for a specified test year
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
ITC	Federal investment tax credit
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PTC	Federal production tax credit
PW1	Port Westward Unit 1 natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired flexible capacity generating plant
QF	Public Utility Regulatory Policies Act of 1978 (PURPA) qualifying facility
RAC	Renewable Adjustment Clause
RCE	Reliability Contingency Event
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant

Tucannon River	Tucannon River Wind Farm
USDOE	United States Department of Energy
Wheatridge	Wheatridge Renewable Energy Facility

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase and sale, transmission, distribution, and retail sale of electricity to customers in the state of Oregon (State). The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers, manage risk, and administer its long-term wholesale contracts. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. A wholly-owned subsidiary of PGE owns unregulated, non-utility property that the Company leases as space for its corporate headquarters.

PGE's State-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2023, the Company added eight thousand customers, and as of December 31, 2023, served a total of 934 thousand retail customers.

Available Information

PGE's periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Company's website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K.

Regulation

Federal and State regulation each have a significant influence on PGE's business operations. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

Regulatory Accounting

PGE prepares financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as: property, plant, and equipment; regulatory assets and liabilities; revenues; certain operating expenses; depreciation expense; and income tax expense. GAAP provides for the deferral, or recording expenses and revenues in periods other than when an unregulated entity would. As a result, the Company may record regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue, or reduce expense, can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future regulatory environment and related accounting guidance. For additional information, see *"Regulatory Assets and Liabilities"* in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Federal Regulation

Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain aspects of PGE's operations and activities, as described in the discussion that follows.

PGE is a "licensee," a "public utility," and a "user, owner, and operator of the bulk power system," as those terms are defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGE's BAA does not have a material impact on the Company.

Transmission—PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC.

Reliability and Cybersecurity Standards—The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help maintain and strengthen the reliable planning and operation of the bulk electric system.

Natural Gas Pipelines—The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile, 20-inch diameter, interstate pipeline that provides natural gas to the Company's three natural gas-fired generating plants located near Clatskanie, Oregon: i) Port Westward Unit 1 (PW1); ii) Port Westward Unit 2 (PW2), and iii) Beaver; the North Mist storage facility, which is owned and operated by a local natural gas distribution company; and one additional delivery point that serves a local manufacturing concern. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety and operator qualification standards in addition to public awareness requirements.

Hydroelectric Licensing—As required under the FPA, PGE holds FERC licenses for all Company-owned and operated hydroelectric generating plants. The FERC license process includes an extensive public review that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the *Generating Facilities* section in Item 2. —"Properties."

Accounting Policies and Practices—PGE prepares periodic and current reports in accordance with GAAP. In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Company's Short-term Debt, see *"Short-term Debt"* in the Debt and Equity section of Liquidity and Capital Resources in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Spent Fuel Storage—The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" and *"Hazardous Material"* in the Environmental Matters section of this Item 1.

State Regulation

PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Company's retail prices and reviews the Company's generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC also regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities.

Retail customer prices are determined through formal public proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order by the OPUC. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following lists the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- *General Rate Cases*. PGE periodically evaluates the need to update its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Company's rate base, debt-to-equity capital structure, return on equity, overall rate of return, and customer prices.
- *Annual Power Cost Updates*. The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Company's net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's consolidated statements of income). NVPC is net of wholesale revenues as well as gains and losses on the sale of excess natural gas not used to fuel PGE's generation facilities included in other operating revenue, both of which are classified as Revenues, net in the consolidated statements of income. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC.
- *Renewable Adjustment Clause mechanism.* The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS.
    - In 2016, the State also passed Oregon Senate Bill (SB) 1547, a law referred to as the Oregon Clean Electricity and Coal Transition Plan, which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers' energy supply. For further information on SB 1547, see "*RPS standards and other laws"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- During 2021, the State legislature passed Oregon House Bill (HB) 2021, which established clean energy targets and set out a framework that includes, among other things, the development and submittal of clean energy plans for investor-owned utilities, including PGE, and electric service suppliers in the State. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For further information on HB 2021 and the baseline to which the target reductions apply, see "*HB 2021"* in the Laws and Regulations portion of the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *Wildfire Automatic Adjustment Clause mechanism.* As required by the OPUC, PGE plans and implements a Wildfire Mitigation Program, developing and coordinating activities across the Company and with state-wide stakeholders. PGE strives to improve regional safety by reducing the risk that PGE's electric utility infrastructure could cause a wildfire, while limiting the impacts of public safety power shutoff (PSPS) events and other mitigation activities on customers and increasing the resiliency of PGE assets to wildfire damage. The OPUC has authorized an Automatic Adjustment Clause mechanism that allows the Company to recover a certain level of ongoing, prudent mitigation expenses in customer prices.

Customers and Revenues

PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to Direct Access customers that choose to purchase their energy from an Electricity Service Supplier (ESS). Although the Company includes such customers in its customer counts, and energy delivered to such commercial and industrial customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers, as the customers purchase energy directly from the ESSs. The Company conducts retail electric operations within its State-approved service territory and competes with ESSs to supply certain commercial and industrial customer energy needs. In addition, PGE competes with the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances. Energy efficiency, demand response, conservation measures, and the advancement of technology around distributed generation, including rooftop solar, and storage resources also have an influence on customer demand.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 9% of PGE's total retail revenues or 14% of total retail deliveries during 2023.

PGE's Retail revenues, retail energy deliveries, and average number of retail customers consist of the following:

	Years Ended December 31,					
	2023		2022		2021	
Retail revenues [1] (dollars in millions):						
Residential	$ 1,263	52 %	$ 1,158	52 %	$ 1,118	54 %
Commercial	808	33	735	33	708	34
Industrial	368	15	312	14	279	13
Subtotal	2,439	100	2,205	99	2,105	101
Alternative revenue programs, net of amortization	11	—	11	1	(29)	(1)
Other accrued (deferred) revenues, net	(3)	—	7	—	2	—
Total retail revenues	$ 2,447	100 %	$ 2,223	100 %	$ 2,078	100 %
Retail energy deliveries [2] (MWh in thousands):						
Residential	7,952	37 %	8,088	38 %	7,978	39 %
Commercial	7,178	34	7,198	34	7,193	35
Industrial	6,293	29	5,945	28	5,361	26
Total retail energy deliveries	21,423	100 %	21,231	100 %	20,532	100 %
Average number of retail customers:						
Residential	815,920	88 %	809,573	88 %	800,372	88 %
Commercial	112,667	12	112,602	12	111,569	12
Industrial	273	—	269	—	268	—
Total	928,860	100 %	922,444	100 %	912,209	100 %

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

The following table presents additional annual averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Company's base retail prices for these calculations.

	Years Ended December 31,		
	2023	2022	2021
Residential			
Revenue per customer (in dollars):	$ 1,481	$ 1,362	$ 1,320
Usage per customer (in kilowatt hours):	9,746	9,991	9,968
Revenue per kilowatt hour (in cents):	15.20 ¢	13.63 ¢	13.24 ¢
Commercial			
Revenue per customer (in dollars):	$ 7,133	$ 6,491	$ 6,303
Usage per customer (in kilowatt hours):	63,713	63,923	64,478
Revenue per kilowatt hour (in cents):	11.20 ¢	10.15 ¢	9.78 ¢
Industrial			
Revenue per customer (in dollars):	$ 1,347,661	$ 1,156,371	$ 1,044,314
Usage per customer (in kilowatt hours):	23,052,538	22,097,472	20,002,246
Revenue per kilowatt hour (in cents):	5.85 ¢	5.23 ¢	5.22 ¢

For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of the weather and seasonal temperature changes lead to variations in both heating and cooling needs. Based on the climate in PGE's service area, the heating season tends to span a longer time period while cooling needs, although robust, are reflected over a shorter span concentrated in the summer months of June through September.

Economic conditions can also affect residential demand as job growth and population growth in PGE's service territory have led to customer growth. The COVID-19 pandemic introduced additional behavioral patterns that reflected the shift that occurred with respect to hybrid work schedules as residential customers spend more time at home. Residential demand is also impacted by energy efficiency measures and increased rooftop solar penetration in the service territory; however, the Company's decoupling mechanism was intended to mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see *"Decoupling"* among the *Regulatory Matters* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Company's commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can be indicative of changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, as measures have focused on the commercial sector in recent years, although the Company's decoupling mechanism was intended to partially mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see *"Decoupling"* among the *Regulatory Matters* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having limited impact on this customer class.

Customer Choice Programs—In addition to standard cost-of-service pricing, the Company offers different pricing options. Under cost-of-service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing.

Pricing options other than cost-of-service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an ESS.

PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Company's cost-of-service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate.

In 2020, the OPUC issued an order that required PGE to begin offering, to eligible customers, enrollment in the New Large Load Direct Access program, which is capped at 119 MWa in total, for unplanned, large, new loads and large load growth at existing sites.

For further information regarding Direct Access deliveries, see "Customers and demand" in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

PGE's customers have a desire for purchasing clean energy, as over 233 thousand residential and small commercial customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. Oregon's most populous city, Portland, and most populous county, Multnomah, have each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area have set, or are considering, similar goals.

As approved by the OPUC in 2019, the Company implemented the Green Future Impact Program, which allowed for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources, that provides commercial and industrial customers access to bundled renewable attributes from those resources. In March 2021, the OPUC issued an order that expanded the program by 200 MW and provided for a utility owned, cost-of-service resource option under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable, integrated power while providing customer choice and a cleaner energy system. In December 2021, the OPUC issued an order, which further increased capacity under the customer-provided renewable resources by 250 MW, to bring the total available capacity under the program to 750 MW. For more information on the Company's power purchase agreements that currently serve the Green Future Impact Program, see *"Green Future Impact Program"* within *Purchased Power* in the Power Supply section of this Item 1.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of, and obtain reasonably-priced power for, its retail customers, manage risk, and administer its long-term wholesale contracts. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand. PGE's engagement in the wholesale electricity marketplace depends upon numerous factors, including the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. The Company also participates in the California Independent System Operator's western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 14% of total revenues in 2023 and 2022, and 11% in 2021.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2023 and 2022, and 3% in 2021.

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial and industrial customers is affected by seasonal weather conditions. The Company uses various measures, including heating and cooling degree-days and wind speeds to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a prescribed baseline, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The greater the number of degree-days, the greater the expected demand for electricity.

The following table presents the heating and cooling degree-days for the most recent three-year period, along with current 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	Cooling Degree-Days
2023	3,845	898
2022	4,103	865
2021	3,828	838
15-year average	4,085	600

In August 2023, PGE set a new all-time high net system load peak of 4,498 megawatts (MW), surpassing the previous all-time peak that occurred in June 2021. In December 2022, the Company recorded its current winter peak of 4,113 MW. The following table presents PGE's average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As illustrated, although the average winter loads continue to exceed average summer loads, the Company has seen its highest annual peak loads during the summer months in recent years:

	Winter Loads			Summer Loads		
	Average	Peak	Month	Average	Peak	Month
2023	2,756	3,661	January	2,512	4,498	August
2022	2,773	4,113	December	2,529	4,255	July
2021	2,659	3,629	December	2,492	4,453	June

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, distributed generation including rooftop solar, transportation and building electrification, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company may need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also performs portfolio management and wholesale market sales services for third parties in the region. In addition, the Company encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage.

PGE's resource and contracted capacity (in MW) was as follows:

	As of December 31,			
	2023		2022	
	Capacity	%	Capacity	%
Generation:				
Thermal [1]:				
Natural gas	1,811	32 %	1,842	32 %
Coal	296	5	296	5
Total thermal	2,107	37	2,138	37
Wind [2]	817	14	817	15
Hydro [3]	432	8	419	7
Total generation	3,356	59	3,374	59
Purchased power:				
Long-term contracts:				
Hydro [3]	792	14	871	15
PURPA qualifying facilities [4]	315	6	315	5
Dispatchable standby generation	131	2	144	2
Capacity	100	2	100	2
Wind [2]	300	5	300	5
Solar [5]	219	4	57	1
Biomass	10	—	10	—
Total long-term contracts	1,867	33	1,797	31
Short-term contracts	442	8	597	10
Total purchased power capacity	2,309	41	2,394	41
Total resource capacity	5,665	100 %	5,768	100 %

(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant.
(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions.
(3) Capacity represents most favorable operating conditions and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%, dependent upon river flows.
(4) Capacity represents contracted capacity for power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act of 1978 (PURPA).
(5) Capacity includes 50 MW from the solar component of Wheatridge. The Wheatridge facility also includes 30 MW related to the battery component which is not reflected in the table above.

For information regarding actual generating output and purchases for the years ended December 31, 2023 and 2022, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

PGE's generating resources consist of six thermal plants (natural gas- and coal-fired), three wind farms, and seven hydroelectric facilities. The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty).

The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the State, see *"RPS standards and other laws"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW.

During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a nameplate capacity of 200 MW through a power purchase agreement.

PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind Development in Eastern Montana (Clearwater). Substantial completion of the project was achieved on January 5, 2024. PGE will own 208 MW of production capacity in these agreements. This additional wind capacity is not reflected in the table above. For more information regarding Clearwater, see "*The Resource Planning Process*" within the "*Overview"* section of Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River.

As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGE's ownership interest in the project is 50.01%. 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's ownership percentage would exceed 50%. PGE purchases 100% of the CTWS's share of the project output. For more information see *"CTWS"* within *Purchased Power* in the Power Supply section of this Item 1.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company utilizes financial instruments such as forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy.

PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico by Williams. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company.

PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants.

PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility, owned and operated by NW Natural, may be utilized to provide fuel to PW1, PW2, and Beaver.

To serve Coyote Springs and Carty, PGE has access to 119,500 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing the gas market in Alberta, Canada.

Coal The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits. For more information regarding Colstrip coal supply, see "*Westmoreland Mine Permits*" within Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements, manage risk, and administer its long-term wholesale contracts. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis.

PGE's medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE attempts to mitigate a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Hydro—During 2023, the Company had the following agreements:

- *Public Utility Districts*—PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 331 MW of capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time:
    - 100 MW of capacity with Douglas County PUD that expires in 2025;
    - 68 MW of capacity with Douglas County PUD that expires in 2028; and
    - 163 MW of capacity with Grant County PUD that expires in 2052.

PGE has entered into two additional agreements, both beginning January 1, 2024, which are not reflected in the table above:

- a 2-year contract in which PGE will purchase 10% of the project output and sell 25 MW back to the PUD in order to meet their load requirements; and
- a 3-year contract in which PGE will purchase a 20% share of the project output and sell varying amounts of energy in accordance with contract terms back to the PUD in order to meet their load requirements.

- *CTWS*—PGE has a long-term agreement under which the Company purchases output from the CTWS' interest in the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 224 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE pays fixed capacity and energy charges to the CTWS for 100% of its share of the project through 2024. The CTWS exercised their option to purchase an additional undivided 16.66% ownership interest in Pelton/ Round Butte effective January 1, 2022. As a result of the sale, capacity from Company-owned generation decreased by approximately 76 MW, and capacity from purchased power increased by a corresponding amount. Under the PPA, PGE purchases 100% of the CTWS's additional share of the project and payments under the PPA increase proportionately. PGE and the CTWS executed an additional 16-year PPA which begins on January 1, 2025, that effectively extends the term from 2024 to 2040 and increases the capacity payments in the extension period.
- *Other*—The remaining capacity is primarily comprised of two additional contracts that provide for the purchase of power generated from hydroelectric projects with capacity of 236 MW in total:
  - 200 MW of capacity with Bonneville Power Administration (BPA) that expires in February 2024; and
  - 36 MW of capacity with Portland Hydro that expires in 2032.

PURPA qualifying facilities—PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of energy. As of December 31, 2023, PGE had contracts with 69 online QFs, providing a total of 315 MW of capacity. As of December 31, 2023, PGE had two contracts with QFs representing 116 MW of capacity that are not yet operational, of which one of the QF PPAs is in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF must cure its default within a period specified under the contract terms. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years.

The expense and volume of purchases from QFs for the years ended December 31, 2023 and 2022 were as follows:

	2023	2022
PURPA contract expense (in millions)	$ 63	$ 62
MWh purchased under PURPA contracts (in thousands)	759	750
Average cost per MWh from PURPA contracts	$ 82.85	$ 82.90

Expenses incurred related to PURPA contracts are included in PGE's AUT.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can dispatch and monitor customer-owned backup generators when needed to provide NERC-required operating reserves. As of December 31, 2023, there were 79 customer-owned generators with a total DSG nameplate capacity of 131 MW. PGE continues to pursue expansion of the program through ongoing engagement with customers and incorporation of battery energy storage.

Capacity—PGE has one capacity contract representing up to 100 MW of seasonal capacity during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in February 2024.

Wind—PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2051, respectively. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind Development in Eastern Montana. Substantial completion of the project was achieved on January 5, 2024. PGE will own 208 MW of production capacity in these agreements. Subsidiaries of NextEra Energy Resources, LLC will own the remaining 103 MW of production capacity and will sell their portion of the output to PGE under a 30-year PPA. This additional wind capacity is not reflected in the resource and contracted capacity table above. For more information regarding the Clearwater Wind development, see "*The Resource Planning Process*" within the "*Overview"* section of Item 7— "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Solar—PGE has five contracts representing 219 MW of capacity to purchase power generated from photovoltaic solar projects. Two of these projects extend to 2036 while the other three extend to 2037, 2038, and 2042, respectively. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions. The solar component of Wheatridge supplies the Company with 50 MW of capacity. The facility also includes 30 MW related to the battery component which is not reflected in the resource and contracted capacity table above. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and sell their portion of the output to PGE.

Biomass—PGE has one contract to purchase biomass energy that is set to expire in June 2024.

Green Future Impact Program— PGE has three contracts representing 360 MW of capacity to purchase power generated from renewable resources to support the Green Future Impact Program:

- a 15-year contract with Avangrid Renewables representing 162 MW from a renewable solar facility in Gilliam County, Oregon that was placed in service in January 2023. This capacity is reflected within solar purchased power in the resource and contracted capacity table above;
- a 25-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in January 2026. This additional capacity is not reflected in the resource and contracted capacity table above; and
- a 25-year contract with Avangrid Renewables representing 60 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in January 2026. This additional capacity is not reflected in the resource and contracted capacity table above.

For additional information on the Green Future Impact Program, see "*Customer Choice Programs*" within the Customers and Revenues section of this Item 1.

Short-term contracts—These contracts are for delivery periods of one month to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirements.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. PGE is a market participant in the western EIM, which allows certain of the Company's generating plants to receive automated dispatch signals from the California Independent System Operator (CAISO) for load balancing with other western EIM participants in five-minute intervals.

For additional information regarding PGE's power purchase contracts, see Note 16, Commitments and Guarantees and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE's Integrated Resource Plan (IRP) outlines the Company's plan to meet future customer demand and describes PGE's future energy supply strategy. For a detailed discussion of the IRPs, see *"Investing in a Clean Energy Future"* within the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2023, PGE delivered approximately 28 million megawatt hours (MWh) through 1,254 circuit miles of transmission lines operating at or above 115 kilovolts (kV).

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with BPA to transmit a significant amount of the Company's generation to serve its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's transmission system is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. PGE has joined the Western Power Pool's resource adequacy program known as the Western Resource Adequacy Program (WRAP), which is currently expected to become a binding commitment in 2026. For further information, see "*Operating Activities*" within the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The Company's wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system through PGE's OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous materials. Various state and federal agencies also regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain environmental regulations that affect the Company's operations and facilities.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and GHG emissions in terms of both quantity and rate, among other things. Oregon and Montana, the states in which PGE's thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded pursuant to the CAA.

Climate Change—In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce overall carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP. In 2019, the EPA finalized the more narrowly focused Affordable Clean Energy (ACE) rule, which established guidelines for states to develop plans to address GHG emissions from individual, existing coal-fired plants, such as Colstrip in the case of PGE, to repeal and replace the CPP. However, in January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA. Notwithstanding objections that the EPA intended to issue a new rule that took recent changes in the electricity sector into account, in October 2021, the U.S. Supreme Court agreed to hear an appeal of the D.C. Circuit decision. The Supreme Court, in a February 2022 decision, determined that the broad approach in the CPP regulating emissions exceeded the powers granted to the EPA by Congress. The Court did not expressly determine whether the EPA can regulate power sector GHG emissions through its other regulatory authority. In May 2023, the EPA proposed a successor rule to the CPP including CAA emissions limits and guidelines for carbon dioxide emissions from fossil-fuel fired power plants based on cost-effective and available control technologies. The Company has remained engaged in review of the EPA's proposal that would reduce allowed emissions of CO_2 from generation facilities. It is anticipated that the EPA will put the successor rule into effect in 2024.

PGE will continue to assess the rule making of the EPA, for impacts on Colstrip and the Company's existing natural gas fleet.

In 2020, the Governor of Oregon issued Executive Order 20-04 that directed State agencies to integrate climate change and the State's GHG emissions reduction goals into their plans, budgets, investments, and decisions to the extent allowed by law. Among other things, Executive Order 20-04, which remains in place until withdrawn or superseded:

- directed the Oregon Department of Environmental Quality (ODEQ) to adopt a program to cap and reduce GHG emissions within the State from large stationary sources, transportation fuels, and other liquid or gaseous fuels including natural gas. In response, in 2021, the ODEQ adopted the Climate Protection Plan, which among various provisions, included an exemption for electricity generation from the Company's natural gas-fired resources; and
- modified the reduction goals of the State's Clean Fuels Program and extended the program while increasing the required reduction in average carbon intensity of transportation fuels.

On December 20, 2023, the Oregon Court of Appeals invalidated the ODEQ's Climate Protection Program rules on the basis that the program failed to comply with certain procedural requirements when adopting rules under the CAA. The ODEQ has announced that it will restart a rulemaking process to create a new program. PGE will continue to monitor these developments.

HB 2021—In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. The baseline levels for PGE are the average annual emissions for the years 2010, 2011, and 2012 associated with the electricity sold to its retail electricity consumers as reported to the ODEQ. For additional information, see *"HB 2021"* in the *Laws and Regulations* section of the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHG emissions, the Company would seek recovery in customer prices.

For more information regarding GHG emissions and related environmental regulation, including Oregon's RPS and the Company's goals in this area, see *"Renewable Energy"* under *State Regulation* in the Regulation section of this Item 1. and "Company Strategy" in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Water Quality

Under the federal Clean Water Act, entities that require any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification or permit from the state in which the activity will occur, or obtain an appropriate waiver. In Oregon, Montana, and Washington, the environmental regulatory agencies of each state are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE works continually with state agencies to obtain permits or certificates of compliance needed for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards.

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds and eagles, the Company developed an Avian Protection Plan to help address and reduce risks to avian species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and additional, specific plans for its wind generation facilities.

Hazardous Materials

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

PGE is also subject to the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites.

An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel. The NRC approved the transfer of spent nuclear fuel to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Human Capital Management

PGE's talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented, motivated, and diverse workforce and maintain a culture that reflects PGE's Guiding Behaviors, drive for performance, and commitment to acting with the highest levels of honesty, integrity, compliance, and safety.

Employees and Collective Bargaining Agreements—PGE had 2,842 employees in its workforce as of December 31, 2023, with 661 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). One agreement, which expires March 2025, covers 596 employees, and the other, which expires August 2027, covers 65 employees. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce.

Competitive Pay and Benefits—PGE is committed to pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees.

Talent Development—PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. PGE offers a mentorship program for all regular, non-represented PGE employees to help support their growth and development. The PGE Board of Directors oversees executive talent development with the assistance of the Nominating, Governance, and Sustainability Committee and the Compensation, Culture and Talent Committee in an effort to increase the pool of internal candidates. At least annually, the Board conducts reviews of succession plans for senior management, which includes a review of the qualifications and development plans of potential internal candidates and diversity of the succession pipeline. PGE conducts employee engagement surveys periodically to give employees the opportunity to share their perspectives and provide feedback. Survey results are shared with PGE management so that managers can take action towards improving the employee experience.

Health and Safety—PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Company's efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety. PGE offers a variety of competitive wellness benefits to support physical, mental, social, emotional, and financial well-being. Programs include a digital wellness platform, an Employee Assistance Program that provides free and confidential wellness counseling to all employees and their families, financial education, on-site fitness facilities, volunteer opportunities, company-match on charitable contributions, and tuition reimbursement.

Diversity, Equity, and Inclusion—PGE promotes an inclusive workforce through pay equity practices, racial equity lens training, and development opportunities for employees looking to advance into management. Black, Indigenous, and People of Color comprise over 27% of its employees and management. One third of its employees and over 35% of management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Company's supplier diversity program provides an opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers.

Information about Executive Officers

The following are PGE's current executive officers:

Name	Age	Current Position and Past Five Years Experience	Year Appointed Officer
Larry N. Bekkedahl	62	Senior Vice President, Strategy and Advanced Energy Delivery (December 2023 to present) Senior Vice President, Advanced Energy Delivery (July 2021 to December 2023), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021).	2014
M. Angelica Espinosa	46	Senior Vice President, Chief Legal and Compliance Officer (June 2023 to present) Vice President, General Counsel (March 2022 to June 2023), Deputy General Counsel and Corporate Secretary (June 2021 to March 2022), Chief Risk Officer and Vice President of Safety and Compliance at Southern California Gas Company (January 2019 to June 2021).	2022
Benjamin F. Felton	53	Executive Vice President, Chief Operating Officer (April 2023 to Present), Senior Vice President, Energy Supply at DTE Energy (July 2019 to March 2023), Senior Vice President, Electric Operations at NISOURCE, Co. (October 2018-July 2019).	2023
John T. Kochavatr	50	Vice President, Customer & Digital Solutions and Chief Information Officer (February 2018 to present).	2018
Anne F. Mersereau	61	Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present).	2016
Maria M. Pope	58	President (October 2017 to present) and Chief Executive Officer (January 2018 to present).	2009

Brett M. Sims	55	Vice President, Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020).	2020
Joseph R. Trpik	54	Senior Vice President, Finance and Chief Financial Officer (June 2023 to Present), Senior Vice President, Chief Accounting Officer at Exelon (May 2022 to June 2023), Senior Vice President, Chief Financial Officer and Treasurer at ComEd (November 2021 to May 2022), Senior Vice President, Chief Financial Officer at Exelon Utilities (June 2018 to November 2021).	2023

ITEM 1A. RISK FACTORS.

When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC. The events described in the risk factors could have material effects on PGE's business, financial condition, results of operations, or cash flows, or that materially adversely affect PGE's results and cause such results to differ materially from projected results. Risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial may also harm PGE. If any of these risks occur, PGE's business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Company's securities could substantially decline.

BUSINESS AND OPERATIONAL RISKS

The effects of unseasonable or severe weather and other natural phenomena can adversely affect the Company's financial condition and results of operations, and the effects of climate change could result in more intense, frequent, and extreme weather events.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, high wind, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, and increased risk of wildfires. These events may disrupt energy delivery, cause power outages, or impair the use of, and damage, the Company's facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load, and procure insurance related to such impacts. The increase in additional costs could also have an adverse effect on cash flow and liquidity. In response to more intense, frequent, and severe weather events, PGE may need to make additional investments in generation, transmission, and distribution assets to enhance reliability and resiliency. Weather-related events could also cause system constraints or disrupt transmission flows, resulting in decreased reliability for customers. Severe weather may also require increased PGE personnel availability, which could result in increased operating expenses as well as increased safety risk. In certain instances, PGE relies on mutual aid support to assist in the recovery from severe weather. Lack of availability of mutual aid support could result in increased time to restore services to customers as well as increased costs and decreased customer satisfaction.

Wildfires of greater size and prevalence, such as those of a magnitude seen in Oregon in recent years, could negatively affect public safety, the resilience of the electric grid, customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to provide reliable service to its customers, PGE's ability to access the wholesale energy market, PGE's ability to operate its generating facilities and transmission and distribution systems, PGE's costs to maintain, repair, and replace such facilities and systems, and recovery of costs. PGE may be unable to effectively implement a PSPS and de-energize its system in the event of heightened wildfire risk, or the PSPS may not be able to prevent a wildfire, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm.

Capital investment and operating expenses related to this risk may not be recoverable through increases in customer prices.

Cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events could disrupt PGE's operations, require significant expenditures, or result in claims against the Company.

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that depend on information technology systems. The Company is exposed to, and may be adversely affected by, interruptions to its computer and information technology systems and sophisticated cyber-attacks. As with most companies, PGE has experienced attempts to breach the Company's systems and other similar incidents. A cyber-attack may cause large-scale disruption to the U.S. bulk power system or PGE operations and could target the Company's computer systems, software, or networks to achieve such disruption. Generation, transmission, and distribution facilities, in general, have been identified as potential targets of physical or cyber-attacks. In addition, physical attacks on transmission and distribution facilities have occurred in the United States. Despite the security measures in place, the Company's systems and assets, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt operations, cause damage to the Company's generation, transmission, or distribution facilities, impact reliability of the transmission and distribution system, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGE's ability to initiate, authorize, process, record, and report financial information. The cost of repairing damage to PGE's facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent PGE from providing utility service to its customers, could adversely impact its financial condition and results of operations. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance is limited in scope and subject to exceptions, and may not be adequate to protect the Company against liability in all cases and insurers may dispute or be unable to perform their obligations to the Company, or may not be available at rates that are commercially reasonable. PGE continuously seeks to maintain a robust program of security and controls, but the impact of a physical or material information technology event could have a material adverse effect on the Company's competitive position, reputation, results of operations, financial condition and cash flows.

Natural or human-caused disasters and other risks could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

PGE has exposure to natural and human-caused disasters and other risks, including, but not limited to, a pandemic such as COVID-19, earthquake, accidents, equipment failure, acts of terrorism, acts of vandalism, computer system outages and other events. Such events, which may be amplified by the fact that PGE's business activities are concentrated in one region, could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires or flooding, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight.

Electric utility operations may pose risk to public and workers' safety.

The operation of electric generation, transmission, and distribution infrastructure involves inherent risks, including breakdown or failure of equipment, motor vehicle accidents, fires involving the utility's equipment, dam failure at company-owned hydroelectric facilities, public and worker safety, human contact with energized equipment, and operator error. A portion of the Company's operations relies on Company- or third party-owned natural gas transmission and distribution infrastructure and involves inherent risks, such as leaks, explosions, mechanical problems, and worker and public safety.

These risks could cause significant harm to workers and the public including loss of human life, significant damage to property, adverse impacts on the environment and impairment of PGE's operations, all of which could result in financial losses that would have a material adverse effect on the Company's results of operations and financial condition and reputational harm. PGE is also required to comply with new and changing regulatory standards involving safety compliance. The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines.

The inability to attract and retain a qualified workforce and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGE's results of operations.

PGE's workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented under collective bargaining agreements. Workforce management risks include the risk of retaining key employees, turnover due to demographic challenges as employees approach retirement age, and turnover due to macroeconomic trends such as the impacts of inflation on pensions and other retirement funding. PGE faces competition for employees within the industry and in local geographies. The Company faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize. PGE relies on a contracted workforce for specific business purposes, and may experience increased costs or inability to find contracted workforce, which may result in a negative impact on operations as well as financial impact.

The construction of new facilities and the modifications or replacements of existing facilities is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.

Long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by factors such as unanticipated delays and cost increases, including supply chain disruption and cost inflation, availability of skilled workforce, increases in interest rates, failure of counterparties to perform under agreements, and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities. Delays and cost increases could result in failure to complete the projects or the abandonment of capital projects, which could eliminate or impair PGE's ability to recover related costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

REGULATORY, LEGAL, AND COMPLIANCE RISKS

PGE is subject to extensive price regulation and relies on recovery of costs, the uncertainty of which could affect the Company's operations and costs.

PGE is subject to ongoing regulation by the FERC, the OPUC and by certain federal, state, and local authorities under environmental, permitting, and other laws. Such regulation significantly influences the Company's operating environment and affects many aspects of its business. The Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business, and such changes could delay or adversely affect business planning and transactions and substantially increase the Company's costs.

OPUC regulates the prices that PGE charges, which is a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE relies on customer prices to recover most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements (including environmental laws), and the costs of damage from storms and other natural disasters. Regulators may deny recovery of costs it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just, and reasonable, it has significant discretion in the interpretation of this standard. PGE attempts to manage its costs at levels consistent with OPUC-approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect its results of operations, financial condition, or cash flows.

In the normal course of its business, PGE is subject to regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. Such matters include governmental policies, legislative action, and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs and capital investments, and current or prospective wholesale and retail competition. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could result in disallowance of operating expenses previously deferred or could require that the Company incur expenditures over an extended period and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations. New laws, changes in legal precedent, or novel interpretations of existing regulations could also result in adverse effects on cash flows and results of operations.

There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings," *Regulatory Matters* within the "Overview" of Item 7.— "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Compliance with environmental laws and regulations may result in capital expenditures, increased operating costs and various liabilities, and adverse impacts on the Company's results of operations.

PGE is subject to various environmental laws, regulations, and other standards including federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, emissions of greenhouse gases (GHG) such as carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of fuels required for power generation, require additional pollution control equipment, require investment in non-emitting resources, and otherwise increase costs and increase capital expenditures.

A portion of PGE's total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. Changes to the listing of various plants and species of fish, birds, and other wildlife as threatened or endangered could result in increased mitigation activities, which could have a material impact on PGE's financial condition and results of operations. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, changes to and new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Company's energy requirements.

Compliance with any new or additional GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the retirement or replacement of high-emitting generation facilities with non-emitting facilities. The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material.

Changes in tax laws may have an adverse impact on the Company's financial position, results of operations, and cash flows.

PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the State regulatory commission, which could have a negative effect on the Company's financial condition and results of operations.

PGE owns and operates renewable generating facilities and will own battery storage facilities, which generate federal production tax credits (PTCs) and investment tax credits (ITCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Company's wind facilities resulting in a material adverse impact on PGE's financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings. The Inflation Reduction Act of 2022 allows for the sale or transfer of renewable tax credits to other taxpayers. The Company has sold and plans to continue to sell tax credits. PGE's inability to generate, transfer, or sell these credits could have a material impact on results of operations.

ECONOMIC, FINANCIAL, AND MARKET RISKS

A decrease in customer demand for electricity may negatively impact PGE's business.

Unfavorable economic conditions in Oregon, such as, for example, increased inflation, may result in reduced demand for electricity and impair the financial stability of PGE's customers. Such reductions in demand could adversely affect PGE's results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Company's vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts.

Customer demand could also be negatively impacted by PGE's ability to attract and retain customers, mandated energy efficiency measures, demand side management programs, potential formation of community choice aggregation programs, distributed generation resources, and economic and demographic conditions, such as population changes, job and income growth, new construction, new business formation and the overall level of economic activity. Development, improvement, and adoption of technological advances could lead to declines in energy use per customer. Some or all of these factors could impact the demand for electricity.

The decline in revenues due to decreased customer demand for electricity may increase customer prices for remaining customers, as PGE's revenue requirement is designed to cover its fixed utility operating expenses. Increased customer prices could further reduce customer demand for electricity and strain PGE's ability to attract and retain customers. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for electricity could negatively impact PGE's financial condition and results of operations.

Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan.

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. Volatility of interest rates could negatively impact PGE's cost of debt and results of operations. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects.

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, sales or issuances of substantial amounts of PGE's common stock in the public market could cause the market price of PGE's common stock to decline. This could impair the Company's ability to raise additional capital through the sale of equity securities. Future sales or issuances of common stock or other equity-related securities could be dilutive to holders of common stock and could adversely affect their voting and other rights and economic interests.

PGE expects to raise additional capital in the future. PGE may raise additional funds through public or private equity or debt offerings or other financings, as well as additional borrowings under existing credit facilities. Any new debt financing entered into may involve covenants that restrict operations more than PGE's current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of assets, and prohibitions or limitations on the Company's ability to create liens, pay dividends, receive distributions from subsidiaries, redeem or repurchase stock or make investments. These factors could hinder the Company's access to capital markets and limit or delay the ability to carry out the Company's capital expenditure plan or pursue other opportunities beyond the current capital expenditure plan.

The declaration of future dividends is at the discretion of the Board of Directors and is not guaranteed and, in some circumstances, the payment of dividends may be limited by the terms of PGE's debt instruments.

PGE has historically paid regular quarterly dividends on common stock. However, the declaration of dividends is at the discretion of PGE's Board of Directors and is not guaranteed. The amount of common stock dividends, if any, will depend upon results of operations and financial condition, future capital expenditures and investments, the rights of holders of any outstanding shares of preferred stock, and other factors that the Board of Directors considers relevant.

In addition, the terms of the Company's debt instruments may limit the payment of dividends. Under the Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date, between PGE and Wells Fargo Bank, National Association, so long as any of the first mortgage bonds are outstanding, the Company may not pay or declare dividends (other than stock dividends) on common stock or purchase or retire for a consideration (other than in exchange for other shares of PGE's capital stock or the proceeds from the sale of other shares of capital stock) any shares of capital stock of any class, if the aggregate amount distributed or expended after December 31, 1944 would exceed the aggregate amount of PGE's net income, as adjusted, available for dividends on common stock accumulated after December 31, 1944. At December 31, 2023, $401 million of accumulated net income was available for payment of dividends under this provision.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Credit rating agencies routinely evaluate the Company, and their ratings of long-term and short-term debt are based on a number of factors, including the perceived supportiveness of the regulatory environment affecting the utility operations, the Company's cash generating capability, level of indebtedness, overall financial strength, the status of certain capital projects, as well as factors beyond PGE's control, such as tax reform, the state of the economy and industry generally. A ratings downgrade could increase fees on PGE's syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or S&P Global Ratings (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity and ability to participate in the wholesale markets.

Under certain circumstances, banks participating in PGE's syndicated unsecured revolving credit facility could decline to fund advances requested by the Company or could withdraw from participation in the credit facility, which could adversely affect PGE's liquidity.

PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $750 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event of a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGE's defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the plans. Additionally, changes in interest rates affect PGE's liabilities under the plans. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

The volatility of market prices for power and natural gas could adversely affect PGE's costs and ability to manage its energy supply, which could negatively impact the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. PGE's contract positions may not be fully hedged against commodity prices, and hedges or other risk mitigations may not protect against significant losses.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices. A new mechanism, the Reliability Contingency Event (RCE), which, like the PCAM, allows for cost sharing and deferral of certain costs for specific events, was introduced through the 2024 General Rate Case,. This mechanism expires at the end of 2025.

PGE has put in place risk management policies, procedures, and controls to identify, quantify, and manage risk, however, these systems, processes, tools, and controls may not prevent material losses. Risk management procedures may not always be followed as intended, may not operate as designed, or may not identify all potential risks, including, without limitation, severe weather or employee misconduct. There is no assurance that PGE's risk management procedures will be effective in preventing or mitigating losses, and could have a material adverse effect on the Company's results of operation and financial condition.

Reduced river flows, unfavorable wind conditions, reduced capacity or degradation of solar panels, and forced outages at generating and battery storage facilities can increase the cost of power required to serve customers. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Company's other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs.

Although the application of the PCAM or specific contract terms could help mitigate adverse financial effects from any decrease in power supply, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of PTCs related to wind generating resources.

The capacity provided by the Company's generating resources and third-party purchased power may not be sufficient to meet its customers' energy demand requirements.

PGE meets its customers' energy demand requirements based on capacity obtained from its generating facilities and third-party power purchase agreements. The Company continuously evaluates how much capacity it will need to meet reasonably expected demands of customers and provide reasonable reserves. PGE is also required to file Integrated Resource Plans with the OPUC that detail the Company's plan to meet the future energy and capacity needs of its customers through a least-cost, least-risk combination of energy generation and demand reduction, while also aggressively reducing GHG emissions from the power supply. If the capacity provided by the Company's generating facilities and purchased power is not adequate to meet customers' energy demands, PGE may be required to purchase more power from third parties, invest in acquiring additional generating or battery storage facilities, or invest in extending the operating life of existing generating assets. Any failure to obtain adequate capacity to meet customers' energy demand requirements could increase its costs and negatively impact PGE's customer satisfaction, all of which could have an adverse impact on PGE's business and results of operations.

Advances in energy technology could make PGE's business less competitive.

A basic premise of PGE's business as a vertically integrated utility is the ability to produce electricity at competitive prices due to economies of scale. Furthermore, a key component of PGE's growth is its ability to construct, own, and operate facilities. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. Advancements in and creation of new technologies could include fuel cells and micro turbines, wind turbines, photovoltaic solar cells, distributed generation, nuclear energy, hydrogen, ongoing customer energy efficiency, two-way grid enabling customer-owned generation, and advances in batteries or energy storage. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production or storage to a level that is equal to or below that of existing methods.

The electricity industry is undergoing significant change, including increased deployment of distributed energy resources, technological advancements as described above, and political and regulatory developments. Electric utilities are experiencing increasing deployment of distributed energy resources, such as solar generation, energy storage, energy efficiency and demand response technologies. The deployment of these technologies supports PGE's decarbonization goals. The growth of new technologies will require modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grid's capacity to interconnect these resources. A higher penetration of distributed energy resources may result in decreased customer demand, or may have impacts on grid reliability. Increased distributed energy resources and renewable energy resources will require new and sustained investments in grid modernization and transmission. If all such costs are not recoverable in rates, PGE could experience material increases in its commodity costs, which could impact PGE's results of operations, financial condition, or cash flows.

It is also possible that alternative generation or storage resources are mandated, subsidized, or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply. Competitors may not be subject to the same operating, regulatory and financial requirements that the Company is, potentially causing a substantial competitive disadvantage for PGE. Changes in public policy, such as new tax incentives that PGE cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Such alternative resources and regulatory or legislative actions could displace higher marginal cost generating units or make PGE less competitive in constructing, owning, and operating such facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

Changes in market conditions and environmental laws and regulations could negatively impact PGE's non-utility real estate investments.

PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. A significant change in real estate values could adversely affect PGE's results of operations.

PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGE's T.W. Sullivan hydro generating facility. PGE has recorded a non-utility asset retirement obligation (ARO) for this site related to assets that are no longer in service. Significant changes in estimates for this non-utility ARO due to changes in environmental laws or regulations could adversely affect PGE's results of operations.

Rapidly changing stakeholder expectations and standards with respect to PGE's environmental, social, and governance (ESG) programs could result in increased costs and exposure to incremental risk.

Investors, lenders, rating agencies, customers, regulators, state legislatures, employees, and other stakeholders are increasing their focus on evaluating companies as corporate citizens based on their ESG programs and metrics. Based on PGE's ESG profile, investors and lenders may elect to increase their required returns on capital offered to the Company, reallocate capital, or not commit capital as a result of their assessment of the Company's ESG profile. Such actions by investors and lenders could increase PGE's cost of, or access to, capital and financing.

PGE is committed to the success of its ESG programs; however, if the Company fails to adapt or execute on its ESG strategies, or is perceived to have failed in addressing stakeholder ESG expectations or standards, which continue to evolve, PGE may suffer reputational damage, which could have a material adverse effect on its business, results of operations, and financial condition. Additionally, the cost of implementing and complying with such ESG programs could be material.

Actions of activist shareholders could have a negative impact on PGE's business.

Actions of activist shareholders, which can take many forms and arise in a variety of situations, could include engaging in proxy solicitations, advancing shareholder proposals, or otherwise attempting to effect changes and assert influence on the Company's board of directors and management. Dealing with such actions could result in disruption to company operations, and divert management's and the Company's board's attention and resources from PGE's business and execution of its strategy.

Such shareholder activism could give rise to perceived uncertainties regarding PGE's future, adversely affecting PGE's business opportunities, ability to access capital markets, relationships with its customers and employees, and make it more difficult to attract and retain a qualified workforce. Any such actions could have a material adverse effect on the Company's financial condition and results of operations and could cause fluctuations in the trading prices of its common stock based on market perceptions or other factors.

PGE's business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon or the region.

The Company's industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 1C. CYBERSECURITY.

PGE considers cybersecurity to be a top enterprise risk and manages the risk by following established practices for assessment, protection, response, and oversight. As a utility with critical infrastructure, both cyber and physical security will continue to be an important consideration for the Company's future strategy and operations. The Company maintains a cybersecurity program, overseen by a cross-functional executive committee, that uses a risk-based methodology to support the security of its systems. Additional information about cybersecurity risks and the potential impact to the Company can be found in Item 1A.—"Risk Factors." The Company has not experienced a material cybersecurity incident.

PGE utilizes the cybersecurity framework established by the National Institute of Standard and Technology (NIST) to manage cybersecurity risk. The NIST Cybersecurity Framework provides the foundation for a comprehensive view of the lifecycle for managing cybersecurity risk. All employees are required to take annual cybersecurity awareness training. The Company conducts monthly phishing campaigns in which employees are expected to report suspicious emails. If employees click on the training phishing email, they are provided immediate feedback on how to avoid phishing, in addition to being required to complete additional training. Quarterly security awareness is provided to all employees and focuses on cyber and physical security best practices.

PGE has a threat intelligence function to stay abreast of emerging cybersecurity threats. The Company's threat identification process begins with the development of an inventory of critical enterprise processes and critical assets, which allows the Company to prioritize focus in the event of a threat. PGE's Security Operations Center detects unauthorized entities and actions on the networks and in the physical environment, including personnel activity. Processes are tested regularly, through reviews, audits, and periodic exercises.

PGE engages a third party to attempt to penetrate its systems periodically. The Company also uses a separate third party to conduct an assessment of its cybersecurity program maturity. These assessments allow PGE to upgrade processes and mitigate gaps regularly, rather than having a static program. As a NERC registered entity, PGE is audited triennially by WECC on cybersecurity practices. The most recent audit concluded in 2023.

PGE manages third party cybersecurity risk by conducting due diligence to identify risks from third parties; requiring review and approval before onboarding a third party. Any third party that fails to meet our security requirements is subjected to additional risk screenings. PGE may decide not to move forward with a vendor that does not meet security requirements. PGE also has procured cybersecurity insurance.

Cybersecurity is a top enterprise risk in PGE's enterprise risk management program. An enterprise-wide management group operates to evaluate the cybersecurity program's effectiveness. The Company has an employee who functions as a Chief Security Officer, whose responsibilities include cybersecurity and who has a reporting relationship to senior management. This employee has had a twenty-five year career with the Federal Bureau of Investigation (FBI) prior to joining the Company. She served as the Confidential Advisor to the Director of the FBI, providing strategic advice across all threats allowing her to develop unique and key insights into the global cyber threat landscape, FBI cyber strategy, and cyber operations. Prior to joining the Company, she served as the Special Agent in Charge of the FBI Jacksonville Division where she led all FBI cyber investigations and operations for nation state and criminal actors. PGE has a management-level committee, the Integrated Security Executive Committee (ISEC), specifically dedicated to cybersecurity and risk issues. The ISEC meets twice each quarter and reviews risks, processes, and strategies related to cybersecurity. Members of the ISEC include the Chief Information Officer, the Chief Operating Officer, the Chief Executive Officer, and the Chief Legal and Compliance Officer. In addition, as a top enterprise risk, cybersecurity is also reviewed by the Company's management-level Executive

Risk Committee on an annual basis, or more frequently if circumstances warrant. This broader review allows the cybersecurity risk and mitigations to be aligned with other enterprise risks, including identifying areas of overlap. Members of the Executive Risk Committee include: the Chief Executive Officer, the Chief Legal and Compliance Officer, the Chief Financial Officer, the Chief Operating Officer, the Chief Information Officer, the Senior Vice President of Strategy and Advanced Energy Delivery, and the Vice President of Energy Supply and Regulatory Affairs.

The Audit and Risk Committee of the Board of Directors has oversight of cybersecurity risk and receives briefings on a quarterly basis. The briefings are provided either by the cybersecurity team, together with a senior member of management, or are presented as part of the Audit and Risk Committee's regular review of top enterprise risks, in which cybersecurity risk is reviewed annually or more frequently if circumstances warrant. The Audit and Risk Committee briefs the full Board of Directors at each meeting. In addition, the full Board of Directors has participated in cybersecurity exercises. The Audit and Risk Committee is also provided with information about external assessment results and action plans. There is a process in place to notify the Audit and Risk Committee promptly in the event of a material cybersecurity incident.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are generally located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. The Indenture securing the Company's First Mortgage Bonds (FMBs) constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2023 (in MW):

Facility	Location	Capacity
Wholly-owned:		
Natural Gas or Oil [(1)]*:*		
Beaver	Clatskanie, Oregon	511
Carty	Boardman, Oregon	436
Port Westward Unit 1 (PW1)	Clatskanie, Oregon	393
Coyote Springs	Boardman, Oregon	257
Port Westward Unit 2 (PW2) [(2)]	Clatskanie, Oregon	214
Wind [(3)]*:*		
Biglow Canyon	Sherman County, Oregon	450
Tucannon River	Columbia County, Washington	267
Wheatridge	Morrow County, Oregon	100
Hydro [(4)]*:*		
North Fork	Clackamas River	56
Faraday	Clackamas River	46
Oak Grove	Clackamas River	43
River Mill	Clackamas River	25
T.W. Sullivan	Willamette River	18
Jointly-owned [(2)]**:**		
Coal:		
Colstrip [(5)]	Colstrip, Montana	296
Hydro [(4)]*:*		
Round Butte [(6)]	Deschutes River	187
Pelton [(6)]	Deschutes River	57
Capacity		3,356

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility.
(2) Represents PGE's ownership share.
(3) Represents nameplate ratings. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.
(4) Represents most favorable operating conditions which refers to the set of optimal circumstances under which a power plant or energy generation system can achieve its maximum output capacity efficiently and reliably.
(5) PGE has a 20% ownership interest in the facility, which is operated by Talen Montana, LLC.
(6) PGE has a 50.01% ownership interest in the Pelton/Round Butte hydroelectric project.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the FPA. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. Substantial completion of the project was achieved on January 5, 2024. PGE will own 208 MW of production capacity in these agreements. This additional wind capacity is not reflected in the table above.

Transmission and Distribution

PGE owns or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2023, PGE-owned electric transmission system consisted of 1,254 circuit miles as follows: 287 circuit miles of 500 kV line; 413 circuit miles of 230 kV line; and 554 miles of 115 kV line. The Company also has 28,868 circuit miles of distribution lines that deliver electricity to its customers. PGE also has an ownership interest in, and capacity on, the following:

- 14% of the 2,260 MW transmission facilities between the Colstrip switchyard to the Broadview switchyard, near Billings, Montana, and 16% of the 1,930 MW transmission facilities between the Broadview switchyard and the interconnection point with BPA's transmission system near Townsend, Montana; and
- 20% of the Northwest AC Intertie, a 4,800 MW transmission facility between the John Day Substation near the Columbia River in northern Oregon, and Malin, Oregon, near the California border. The Northwest AC Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to a total of 3,970 MW of BPA transmission systems.

Non-utility Real Estate

PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. As of December 31, 2023, the non-utility property, plant, and equipment balance, net of accumulated depreciation was $75 million, recorded in Other noncurrent assets on the Company's consolidated balance sheets in Item 8.— "Financial Statements and Supplementary Data."

PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGE's T.W. Sullivan hydro generating facility. PGE has recorded a non-utility ARO related to this site. For more information regarding the Company's AROs, see "*Asset Retirement Obligations*" within the "*Critical Accounting Policies and Estimates"* section of Item 7.— "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

ITEM 3. LEGAL PROCEEDINGS.

See Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data," for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the NYSE under the ticker symbol "POR". As of February 8, 2024, there were 694 holders of record of PGE's common stock.

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

For information with respect to securities authorized for issuance under equity-based plans, see Note 13, Equity-based Plans and Note 14, Stock-Based Compensation in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data."

ITEM 6. [RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future results of operations, business prospects, loads, outcome of litigation and regulatory proceedings, capital expenditures, market conditions, events or performance, and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," "based on," "conditioned upon," "considers," "could," "expected," "forecast," "goals," "needs," "promises," "subject to," "targets," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that PGE's expectations, beliefs, or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in such forward-looking statements include:

- governmental policies, legislative action, and regulatory audits, investigations and actions, including those of the FERC, the OPUC, the SEC, and the Division of Enforcement of the Commodity Futures Trading Commission (CFTC) with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs, and capital investments, energy trading activities, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- inflation and volatility in interest rates;
- changing customer expectations and choices that may reduce customer demand for PGE's services may impact the Company's ability to make and recover its investments through rates and earn its authorized return on equity, including the impact of growing distributed and renewable generation resources, changing customer demand for enhanced electric services, and an increasing risk that customers procure electricity from registered ESSs or the adoption of community choice aggregation;
- the timing or outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Regulatory Matters of the "Overview" in this Item 7. and Note 19, Contingencies in the

Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;

- natural or human-caused disasters and other risks, including, but not limited to, earthquake, flood, ice, drought, extreme heat, lightning, wind, fire, accidents, equipment failure, acts of terrorism, computer system outages and other events that disrupt PGE operations, damage PGE facilities and systems, cause the release of harmful materials, cause fires, and subject the Company to liability;
- unseasonable or severe weather and other natural phenomena, such as the greater size and prevalence of wildfires in Oregon in recent years, which could affect public safety, customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, access the wholesale energy market, or operate its generating facilities and transmission and distribution systems, and the Company's costs to maintain, repair, and replace such facilities and systems, and recovery of costs;
- PGE's ability to effectively implement a PSPS and de-energize its system in the event of heightened wildfire risk or implement effective system hardening programs, the inability of which could lead to potential liability if energized systems are involved in wildfires that cause harm, as well as the risk that damages from wildfires may not be recoverable through rates or insurance, resulting in impact to the financial condition or reputation of the Company;
- operational factors affecting PGE's power generating facilities and battery storage facilities, including forced outages, fires, unscheduled delays, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- default or nonperformance on the part of any parties from whom PGE purchases fuel, capacity, or energy, which may cause the Company to incur costs to purchase replacement power and related renewable attributes at increased costs;
- complications arising from PGE's jointly-owned plant, including changes in ownership, adverse regulatory outcomes or legislative actions, or operational failures that result in legal or environmental liabilities or unanticipated costs related to replacement power or repair costs;
- delays in the supply chain and increased supply costs, failure to complete capital projects on schedule or within budget, inability to complete negotiations on contracts for capital projects, failure of counterparties to perform under agreements, or the abandonment of capital projects, any of which could result in the Company's inability to recover project costs, or impact PGE's competitive position, market share, or results of operations in a material way;
- volatility in wholesale power and natural gas prices, including but not limited to volatility caused by macroeconomic and international issues, that could require PGE to post additional collateral or issue additional letters of credit pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, volatility of equity markets as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, the repayments of maturing debt, and stock-based compensation plans, which are relied upon in part to retain key executives and employees;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;

- the effects of climate change, whether global or local in nature, including unseasonable or extreme weather and other natural phenomena that may affect energy costs or consumption, increase the Company's costs, cause damage to PGE facilities and system, or adversely affect its operations;
- changes in residential, commercial, or industrial customer growth, or demographic patterns, including changes in load resulting in future transmission constraints, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- cybersecurity attacks, data security breaches, physical attacks and security breaches, or other malicious acts that cause damage to the Company's generation, transmission, or distribution facilities, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, or result in the release of confidential customer, vendor, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, the ability to recruit and retain key employees and other talent, and turnover due to macroeconomic trends such as voluntary resignation of large numbers of employees similar to that experienced by other employers and industries since the beginning of the COVID-19 pandemic;
- new federal, state, and local laws that could have adverse effects on operating results;
- failure to achieve the Company's greenhouse gas emission goals or being perceived to have either failed to act responsibly with respect to the environment or effectively respond to legislative requirements concerning greenhouse gas emission reductions, any of which could lead to adverse publicity and have adverse effects on the Company's operations and/or damage the Company's reputation;
- social attitudes regarding the electric utility and power industries;
- political and economic conditions;
- the impact of widespread health developments, and responses to such developments (such as voluntary and mandatory quarantines, including government stay at home orders, as well as shut downs and other restrictions on travel, commercial, social, and other activities), which could materially and adversely affect, among other things, demand for electric services, customers' ability to pay, supply chains, personnel, contract counterparties, liquidity and financial markets;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- risks and uncertainties related to current or future All-Source RFP projects, including, but not limited to regulatory processes, transmission capabilities, system interconnections, inflationary impacts, supply chain constraints, supply cost increases (including application of tariffs impacting solar module imports), permitting and construction delays, and legislative uncertainty; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors or assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's consolidated financial statements contained in this report, and other periodic and current reports filed with the SEC.

PGE is a vertically-integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the State. The Company participates in wholesale markets 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 continues to develop products and service offerings for the benefit of retail and wholesale customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory.

Company Strategy

The Company exists to power the advancement of society. PGE energizes lives, strengthens communities, and fosters energy solutions that promote social, economic, and environmental progress. The Company is committed to being a clean energy leader and delivering steady growth and returns to shareholders. PGE is focused on working with customers, communities, policy makers, and other stakeholders to deliver affordable, safe, reliable electricity service to all, while increasing opportunities to deliver clean and renewable energy, reducing greenhouse gas emissions, and responding to evolving customer expectations. At the same time, the Company is building an increasingly smart, integrated, and interconnected grid that spans from residential customers to other utilities within the region. PGE is transforming all aspects of its business to empower its workforce to be even more results oriented to serve customers well. To create a clean energy future, PGE is focused on the following strategic imperatives:

- *Decarbonize Power*—Reduce greenhouse gas (GHG) emissions associated with electricity served to retail customers by at least 80% by 2030 and 100% by 2040;
- *Electrify the Economy*—Increase beneficial electricity use to capture the benefits of new technologies while building an increasingly clean, flexible and reliable grid; and
- *Advance Performance*—Improve safety, efficiency, and system and equipment reliability while maintaining affordable energy service and growing earnings per share 5% to 7% annually.

Climate Change

State-mandated GHG emissions reduction targets—In June 2021, the Oregon legislature passed House Bill (HB) 2021, establishing a 100% clean electricity by 2040 framework for PGE and other investor-owned utilities and electric service suppliers in the State. A number of provisions in the bill align with PGE's strategic direction, and highlight Oregon's ambitious, economy-wide goals to combat climate change. The GHG emissions reduction targets applicable to these regulated entities are an 80% reduction in GHG emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For more information regarding HB 2021 and the baseline to which the target reductions apply, see *"HB 2021"* in the *Laws and Regulations* section of this Overview.

Empowering customers and communities—PGE's customers have a desire for purchasing clean energy, as over 233 thousand residential and small commercial customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. In 2017, Oregon's most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area have similar goals and continue to consider similar goals for the future.

The Company implemented a customer subscription option, the Green Future Impact Program, which is a renewable energy program that allows large business and municipality customers to have a choice in how they source their electricity. Under the Green Future Impact Program, customers can enroll in a Customer-Supplied Option (CSO) or PGE-Supplied Option (PSO). Under the CSO, participants are responsible for finding a renewable energy facility that meets established requirements and bringing those resources to PGE. Under the PSO, customers who enrolled in Phase I can receive energy from PGE-provided purchased power agreements (PPAs) for renewable resources and customers who enroll in Phase II can receive energy either from PGE-provided PPAs for renewable resources or energy from renewable resources that are PGE owned, under certain conditions.

As of December 31, 2023, the Green Future Impact Program has an approved capacity of 750 MW nameplate. Through this voluntary program, the Company seeks to support the customers' clean energy acceleration, achieve PGE sustainability goals, mitigate cost and manage risk, and reliably integrate power.

***The Climate Pledge*—**In 2021, PGE joined The Climate Pledge, a commitment to be net-zero annual carbon emissions by 2040, which is a decade ahead of the Paris Agreement's goal of 2050. As a signatory to The Climate Pledge, PGE agrees to: i) measure and report GHG emissions on a regular basis; ii) implement decarbonization strategies in line with the Paris Agreement through real business changes and innovations, including efficiency improvements, renewable energy, materials reductions, and other carbon emission elimination strategies; and iii) neutralize any remaining emissions with additional, quantifiable, real, permanent, and socially-beneficial offsets.

Severe weather—In recent years, PGE's territory has experienced unprecedented heat, historic ice and snowstorms, and wildfires. On January 13, 2024, the Company's service territory encountered the first of a series of severe winter weather events, including snow, ice, and high winds that caused catastrophic damage to physical assets and resulted in widespread customer power outages. For more information regarding the January 2024 severe winter weather events, see "*Declared States of Emergency*" within this Overview section of this Item 7. August 2023 experienced a record-breaking heat wave with temperatures in the region reaching all-time recorded highs for the month. This resulted in a peak load demand of 4,498 MW, beating the Company's previous all-time peak load demand, and surpassing the prior summer peak load by nearly 6%. The increase and severity of extreme weather events highlights the importance of combating the effects of climate change through decarbonizing the power supply and investing in a more reliable and resilient grid.

Investing in a Clean Energy Future

The Resource Planning Process—PGE's resource planning process includes working with customers, stakeholders, and regulators to chart the course toward a clean, affordable, and reliable energy future. With the passage of HB 2021, PGE created a Clean Energy Plan (CEP), which articulates the Company's strategy to meet the 2030, 2035, and 2040 emission reduction targets through an equitable transition to a decarbonized grid. The CEP is based on, and was filed in connection with, the Company's 2023 IRP. PGE filed its first combined IRP and CEP with the OPUC on March 31, 2023. That filing projects PGE's resource and capacity needs over the next 20 years and proposes an Action Plan to meet near-term needs, subject to the new HB 2021 emissions reduction requirements.

Throughout the remainder of 2023, PGE refreshed its forecasts, first in an Addendum filed July 7, 2023 then several times in subsequent comments in the CEP and IRP docket with the OPUC (LC 80). PGE currently estimates a total resource need of approximately 3,500 to 4,500 MW of renewable energy and non-emitting capacity in order to meet the Company's 2030 emissions reduction target. Through the 2021 All-Source RFP, PGE procured 311 MW of wind resources and 475 MW of capacity, leaving a remaining need to procure approximately 2,700 to 3,700 MW.

On January 25, 2024, the OPUC acknowledged PGE's IRP, subject to certain conditions, providing regulatory support for the Company to pursue the near-term resource additions articulated in the Action Plan. However, the OPUC declined to acknowledge the CEP, directing the Company to provide additional forecast of its emission reductions based on new analysis in the CEP/IRP Update to be filed in January 2025. PGE will continue to pursue its 2023 All-Source RFP while revising forecasts of emissions in the CEP.

2021 All- Source RFP

In 2021, PGE initiated its 2021 All-Source RFP public process, seeking approximately 1,000 MW of renewable resources and non-emitting dispatchable capacity, to fill the need identified in the 2019 IRP action plan and to meet a portion of the Company's estimated 2030 need.

Pursuant to the 2021 All-Source RFP process, PGE has entered into agreements to acquire the following:

- *Clearwater Wind Development*—PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind Development in Eastern Montana. PGE will own 208 MW of production capacity of the 311 MW in these agreements, with an initial expected investment of approximately $415 million, excluding an allowance for funds used during construction (AFUDC). Subsidiaries of NextEra Energy Resources, LLC will own the remaining 103 MW of production capacity and will sell their portion of the output to PGE under a 30-year PPA. Subsidiaries of NextEra Energy Resources, LLC were to design, build, and operate the facility. As of December 31, 2023, the Company has recorded $411 million, including AFUDC, in construction work-in-progress related to Clearwater. Substantial completion of the project was achieved on January 5, 2024 at a placed-in-service cost of $419 million, with $6 million in expected trailing costs remaining.
- *Seaside Grid*—PGE entered into an agreement to construct a 200 MW Battery Energy Storage System (BESS) in Portland, Oregon. PGE will own the resource, with an investment of approximately $360 million, excluding AFUDC. The project has an estimated commercial operation date of June 30, 2025.
- *Constable BESS*—PGE entered into an agreement to construct a 75 MW BESS in Hillsboro, Oregon. PGE will own the resource, with an investment of approximately $150 million, excluding AFUDC. The project has an estimated commercial operation date of December 31, 2024.
- *Troutdale Grid*—PGE entered into a storage capacity agreement for a 200 MW BESS in Troutdale, Oregon. NextEra Energy Resources, LLC will own the resource and will sell the capacity to PGE under a 20-year storage capacity agreement. The project has an estimated commercial operation date of December 31, 2024.

The Clearwater agreements and all BESS agreements represent the final procurement from the 2021 All-Source RFP. Resources required to meet the remaining 2030 need are anticipated to be procured through future acquisition processes, including, but not limited to, the 2023 All-Source RFP and future RFPs.

All BESS projects will be directly interconnected to PGE's system. Energy discharge of BESS projects is reflective of the emission characteristics of the energy utilized to charge the facility. BESS projects do not add incremental emissions to the grid, and therefore, are non-emitting dispatchable capacity resources. The BESS agreements will qualify for the federal investment tax credit (ITC). The Clearwater agreements will qualify for PTCs and will be eligible under Oregon's RPS. The agreements will be subject to prudency review by the OPUC.

In February 2022, NewSun Energy LLC (NewSun) filed a petition for judicial review in the Marion County Circuit Court against the OPUC, challenging the scoring methodology in the 2021 All-Source RFP. PGE joined in the case as an intervenor. NewSun also filed a motion to stay the 2021 All-Source RFP process, which the Court subsequently denied. The OPUC filed a motion to dismiss the case and PGE joined the OPUC's motion to dismiss. NewSun opposed the motion. In May 2022, the Court granted the motion to dismiss to which NewSun responded in June 2022 by filing a notice of appeal with the Court of Appeals of the State of Oregon. After receiving multiple extensions, NewSun filed its opening brief in the appeal in February 2023 and PGE filed a response brief on June 1, 2023. On August 1, 2023, PGE filed a notice asking the Court to dismiss the case. That motion remains pending. Oral argument in this case is scheduled for March 18, 2024.

In October 2022, NewSun filed a petition in Deschutes County Circuit Court seeking review of the OPUC order acknowledging, with conditions, PGE's 2021 All-Source RFP shortlist. PGE intervened in this case and, on March 16, 2023, filed a motion to dismiss. On September 7, 2023, the judge granted PGE's motion to dismiss. On November 19, 2023, NewSun filed a notice of appeal in the Court of Appeals of the State of Oregon.

PGE cannot predict the outcome of these proceedings or potential impact, if any, to its ongoing 2021 All-Source RFP process.

2023 All-Source RFP

PGE filed notice with the OPUC on January 31, 2023 that an RFP in 2023 was needed to procure resources to meet a forecasted 2026 capacity shortfall and to make continued progress toward decarbonization targets under HB 2021. These actions were consistent with the 2023 IRP Action Plan and CEP. The filing included PGE's request for a partial waiver of the OPUC's competitive bidding rules, which was approved by the OPUC on April 18, 2023, and outlined PGE's recommended timeline for obtaining necessary regulatory approvals. PGE filed the draft 2023 All-Source RFP with the OPUC on May 19, 2023 and regulatory approval was granted in January 2024. The Company issued the RFP to market on February 2, 2024, seeking bids for resources that can provide non-emitting dispatchable capacity and renewable generation. The Company will accept and evaluate bids during the first quarter of 2024 and present a shortlist of top-performing projects for OPUC acknowledgement later in the year.

Transmission Upgrades

In alignment with local and regional transmission plans, the 2023 IRP Action Plan, and CEP, PGE is evaluating and implementing upgrades to existing transmission resources and expansions of current transmission networks. Transmission resource actions are intended to alleviate congestion, improve regional adequacy and reliability, enable decarbonization goals, and address growing customer demand.

Building a resilient grid—To serve communities with clean energy, PGE's grid of the future will need to be smart and adaptive. Highlights of PGE's key investments and plans for building a resilient grid include:

- *Wildfire Mitigation*—PGE plans and implements a Wildfire Mitigation Program (WMP), developing and coordinating activities across the Company and with state-wide stakeholders. The 2024 WMP forecasts $45 million in operations and maintenance costs and an additional $43 to $49 million in capital investments to continue system hardening efforts, expand situational awareness capabilities, implement specific inspection and maintenance along with vegetation management, raise community and customer awareness, and take operational actions within high fire risk zones. PGE strives to improve regional safety by reducing the risk that PGE's electric utility infrastructure could cause a wildfire, while limiting the impacts of PSPS events and other mitigation activities on customers and increasing the resiliency of PGE assets to wildfire damage. During 2023, PGE invested $18 million in capital projects related to wildfire mitigation and resiliency and utility asset management, consistent with the 2023 WMP.
- *Virtual Power Plant (VPP)*—PGE's VPP is a production resource comprised of Distributed Energy Resources (DERs) and flexible loads that are managed through technology platforms to provide grid and power operations services. PGE's customer offerings related to energy efficiency and flexible load programs, rooftop solar, battery storage, and electric vehicle charging solutions support grid reliability and increase portfolio flexibility and resource diversity. These distributed energy resources are the foundation of PGE's VPP that will provide a growing suite of grid and system services over time. When coordinated through the Company's DER Management Systems, DERs and flexible loads support cost-effective decarbonization, advance customer and community energy resiliency, promote customer engagement with the energy system, and unlock additional grid services that enhance PGE's operation of a dynamic two-way system. In 2023, PGE saw record energy demand of 4,498 MW on August 14. Customer actions that day, orchestrated through the VPP, reduced load by more than 90 MW, helping avoid customer service interruptions and reducing exposure to scarcity pricing in energy markets.
- *Distribution System Plan (DSP)*—In 2021 and 2022, PGE filed its inaugural DSP in two parts, which were accepted by the OPUC in March 2022 and February 2023, respectively. The DSP outlines distribution system assets, describes how the Company plans for new load including distributed resources such as electric vehicles (EVs) and Solar Photovoltaic installations, and presents the vision for modernizing the grid to enable accelerated decarbonization and customer participation in meeting PGE's clean energy goals. The Company is in the process of compiling the next DSP, which is expected to be filed by the first quarter of 2025.

Electrify the economy—To help Oregon reach its decarbonization goals, PGE is working to build a safe, reliable, and affordable, economy-wide, clean energy future. The Company is committed to increasing electrification of buildings and supports the accelerating pace of vehicle electrification for our customers, as well as its own vehicle fleet.

Transportation electrification is one of the most significant ways to reduce GHG emissions in Oregon. PGE is engaged with customers and communities to manage electric vehicle (EV) charging load, develop infrastructure projects aimed at improving accessibility to electric vehicle charging stations, build fleet partnerships, and offer programs to encourage customers to advance transportation electrification.

In 2021, the Oregon legislature enacted HB 2165, ensuring the OPUC has clear and broad authority to allow electric company investments in infrastructure to support transportation electrification. In 2023, PGE's second Transportation Electrification (TE) plan was filed and accepted by the OPUC. The TE plan considers current and planned activities, along with EV forecasts and potential system impacts. The 2023 TE plan represents a continuation of the approach and programmatic efforts found within PGE's 2019 TE plan while also outlining the Company's current strategy to integrate TE into utility business in order to plan, service, and manage EV load.

In the 2023 to 2025 period covered by the 2023 TE plan, capital expenditures are expected to be approximately $25 million. The final 2023 TE plan was accepted by the OPUC on October 17, 2023. In October 2023, the OPUC accepted the planned activities associated with TE.

Businesses and families continue to turn to electricity to serve their home and workplace needs. PGE continues to pursue advanced technologies to enhance the grid, pursue distributed generation and energy storage, and develop microgrids and the use of data and analytics to better predict demand and support energy-saving customer programs.

Laws and Regulations

Federal Grants—In November 2021, the $1.2 trillion Infrastructure Investment and Jobs Act (IIJA), which includes approximately $550 billion of new federal spending, was signed into law. PGE continues to pursue multiple areas under the IIJA, and other state and federal programs, for potential grant funding of projects. These projects target improvements in electrical system reliability and resiliency, wildfire situational awareness and mitigation, greater communications capabilities, advancements in customer usage analytics using artificial intelligence, renewable resources and advanced electrical grid support, hydro generation operations, hydrogen production, and regional transmission capacity constraints.

As of December 31, 2023, PGE has submitted 16 full federal grant applications and has been awarded eight grants totaling $314.4 million, including the following:

- *U.S. DOE Bethel-Round Butte Transmission Line Upgrade*—The U.S. DOE selected the Confederated Tribes of Warm Springs (CTWS), in partnership with PGE, for a $250 million grant to upgrade the existing 230 kV Bethel-Round Butte Transmission line to 500 kV. The project will accelerate the development of transmission capacity, enabling new carbon-free generation in Central and Eastern Oregon to reach customer demand loads in Western Oregon. The added capacity and associated upgrades will also increase resiliency of the transmission system as well as resiliency of the CTWS Tribal communities by increasing resources available to the Tribes to support adaptation and response strategies. The U.S. DOE and PGE are negotiating the final funding and scope for the line upgrade as part of a multi-year process.
- *U.S. DOE Smart Grid Chip*—The U.S. DOE selected a PGE-led consortium for a $50 million grant for the Smart Grid Chip project. The project will enable real-time information at each meter to improve the visibility of the electrical system to grid operators, providing detection of potential operational problems and shorten outage times, ultimately helping to anticipate and mitigate the impacts of extreme weather on grid resiliency. The DOE and PGE are negotiating the final funding and scope for the project as part of a multi-year process.

PGE is in the process of assessing the impacts of these federal grants on the Company's results of operations. Although PGE continues to apply for additional grants, the Company cannot predict the ultimate timing and success of securing funding from federal programs.

Inflation Reduction Act of 2022—The Inflation Reduction Act of 2022 (IRA) was signed into law in August 2022 with a majority of the provisions effective for tax years beginning after December 31, 2022.

The United States Treasury and the Internal Revenue Service released extensive rules addressing credit transfer eligibility and application, including but not limited to, required registration, filing, and documentation for transferors and transferees to elect and claim a credit transfer. On December 12, 2023, PGE received approval from the OPUC to transfer 2023 production tax credits and record any difference in the full value and the discounted value in a property balancing account. Consistent with options available under the IRA, PGE sold credits during 2023 and intends to sell credits in the future.

Compared to previous resource planning processes, the Company believes the new tax incentives will provide additional investment opportunities for PGE and result in lower customer prices. Increased capital expenditures in such investment opportunities would likely result in additional financing needs through debt and equity instruments.

HB 3143—In June 2023, the Oregon Legislature passed HB 3143, which was signed by the Governor on August 1, 2023. HB 3143 allows the OPUC to authorize the State's investor-owned utilities, including PGE, to issue bonds and securitize debt for expenses associated with declared emergency events. The bill enables PGE, after a public process and rigorous review and approval by the OPUC, to issue, at a minimum, investment grade bonds to pay for the costs of declared emergencies.

HB 2021—In June 2021, the Oregon Legislature passed HB 2021, which, among other things, requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. For PGE, the baseline levels are the average annual emissions for the years 2010, 2011, and 2012 associated with the electricity sold to its retail electricity consumers as reported to the Oregon Department of Environmental Quality (ODEQ).

HB 2021 requires utilities to develop a CEP for meeting the targets, concurrent with each IRP, and to develop a DSP that establishes reasonable costs for retail electricity consumers. In reviewing a CEP, the OPUC must ensure that utilities plan for equitable implementation, demonstrate continual progress, and take actions as soon as practicable that facilitate rapid reduction of GHG emissions.

Regulated entities are required to, and will continue to, report annual GHG emissions to the ODEQ, as they are required to do today. In threshold years, and every year thereafter, the OPUC will use the data reported to the ODEQ for that compliance year to determine whether the reduction targets are met.

Utilizing the methodology per the ODEQ's Greenhouse Gas Reporting Protocol for investor-owned utilities, PGE's preliminary percentage of 2023 retail load served by non-emitting resources is 32 percent as of December 31, 2023.

Governor executive order—In 2020, the Governor of Oregon issued Executive Order 20-04 that directed State agencies to integrate climate change and the State's GHG emissions reduction goals into their plans, budgets, investments, and decisions to the extent allowed by law. Among other things, Executive Order 20-04, which remains in place until withdrawn or superseded:

- directed the OPUC to encourage electric companies to support transportation electrification infrastructure;
- directed the ODEQ to adopt a program to cap and reduce GHG emissions within the State from large stationary sources, transportation fuels, and other liquid or gaseous fuels including natural gas. In response, in 2021, the ODEQ adopted the Climate Protection Plan, which among various provisions, included an exemption for electricity generation from the Company's natural gas-fired resources; and
- modified the reduction goals of the State's Clean Fuels Program and extended the program while increasing the required reduction in average carbon intensity of transportation fuels.

PGE continues to monitor activities of State agencies that have utilized Executive Order 20-04 to shape State policy or seek to implement it through their own regulatory authority.

RPS standards and other laws—In 2016, Oregon Senate Bill (SB) 1547 set a benchmark for the percentage of electricity that must come from renewable sources and required the elimination of coal as a fuel for generation of electricity used to serve Oregon utility customers no later than 2030.

PGE ceased coal fired operation at its Boardman generating facility (Boardman) in 2020 and decommissioning of the plant is substantially complete. The Company has a 20% ownership share in Colstrip Units 3 and 4 coal-fired generation plant (Colstrip) and in response to SB 1547, PGE filed a tariff request in 2016 with the OPUC and received approval to accelerate recovery of the Company's investment in Colstrip from 2042 to 2030.

Effective May 9, 2022, PGE's depreciation rates and associated customer prices changed as approved by the OPUC in the Company's 2022 General Rate Case (GRC) to reflect further accelerated depreciation of Colstrip from 2030 to December 31, 2025. In order to meet PGE's regulatory and legislative requirements, the Company continues to evaluate the possibility of exiting ownership in Colstrip. See Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" for information regarding legal proceedings related to Colstrip.

Any reduction in generation from Colstrip has the potential to provide additional capacity availability on the Colstrip transmission facilities, which stretch from eastern Montana to near the western end of that state to serve markets in the Pacific Northwest and neighboring states. PGE has an approximate 15% ownership interest in, and capacity on, the Colstrip transmission facilities. See *"Investing in a Clean Energy Future"* in this Overview for information regarding development in eastern Montana.

Other provisions of SB 1547:

- establish RPS thresholds of 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- limit the life of renewable energy credits (RECs) generated from facilities that become operational after 2022 to five years, but continue unlimited lifespan for all existing RECs and allow for the generation of additional unlimited RECs for a period of five years for projects online before December 31, 2022; and
- provide opportunity to pursue recovery of energy storage costs related to renewable energy in the Company's RAC filings.

For a more comprehensive review of Environmental Matters, see "Environmental Matters" in Item 1.—Business.

Regulatory Matters

PGE focuses on providing reliable, clean power to customers at affordable prices while providing a fair return to investors. To achieve this goal the Company must execute effectively within its regulatory framework and maintain prudent management of key financial, regulatory, and environmental matters that may affect customer prices and investor returns. The following discussion provides detail on such matters.

General Rate Case—In February 2023, PGE filed with the OPUC a GRC based on a 2024 test year (2024 GRC). All items, including NVPC, have been resolved. The OPUC authorized a:

- capital structure of 50% debt and 50% equity;
- return on equity of 9.5%; and
- cost of capital of 6.993%, which reflects updates for actual and forecasted debt costs.

The OPUC approved an annual revenue requirement increase of $391 million and an average rate base of $6.2 billion. New customer prices, as approved by the OPUC, became effective January 1, 2024.

Key elements of the OPUC's Orders in the 2024 GRC include:

- resolution of all issues concerning recovery of costs included in the 2024 GRC for the Faraday Resiliency and Repowering Project;
- provision, which will sunset after December 31, 2025, to recover 80% of costs for Reliability Contingency Events (RCE), as defined in the settlement, above amounts forecasted in the AUT without application of an earnings test, and allowance for the remaining 20% to flow through the existing PCAM;
- establishment of a balancing account that will sunset after December 31, 2026, for recovery of routine vegetation management expenses; and
- authorization of a tariff filing, which the Company submitted to the OPUC on January 26, 2024, that proposes for residential and small non-residential customers weather-normalized decoupling that would sunset after December 31, 2025.

Complete details of the 2024 GRC (OPUC Docket UE 416) is available on the OPUC Internet website at www.oregon.gov/puc.

COVID-19 impacts**—**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. 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**—**Under SB 762, enacted in July 2021, PGE encountered incremental costs and investments related to intensifying efforts on its system to mitigate the risk of wildfire and improve resiliency to wildfire damage. 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 PSPS, 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, net of amortization, was $29 million and $28 million, respectively. The 2023 balance is comprised of:

- Base Rates - The outcome of PGE's 2022 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, PGE will remove collections related to wildfire mitigation costs (for both capital and expense) from base prices and include the forecasted costs within the automatic adjustment clause in a separate tariff to begin April 1, 2024. 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.

***Declared states of emergency*—**In September 2021, the OPUC issued an order that approved a pre-authorized deferral of costs associated with declared states of emergency. Qualifying events would include federal or state declared emergencies with impacts on PGE's service territory. Previously the Company had to file a request for deferred accounting when an event of that nature occurred, and had to seek OPUC approval of such deferred accounting applications to be effective. With this order, PGE would provide notice of an event that qualifies within 30 days of the declared state of emergency and would not need to seek OPUC approval to apply deferred accounting treatment for incremental costs related to the emergency. The OPUC maintains responsibility to review utility requests to amortize deferred amounts in customer prices, including a review of utility prudence in a future proceeding, among other requirements. As of December 31, 2023, PGE had not recorded any costs under this deferral order.

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 currently estimates the incremental incurred and future costs to repair damage to PGE's transmission and distribution systems and restore power to customers could range from $50 million to $60 million, with $35 million to $45 million of that range estimated to represent operating expenses associated with transmission and distribution. 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 costs as regulatory assets.

Due to the storm and corresponding impact on power markets, PGE has incurred a substantial amount of incremental net variable power costs compared to what was anticipated in the 2024 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. Estimates of the total cost for the RCE are still under development, however the Company believes total costs could be in the range of $85 million to $100 million. Full impacts cannot be determined until all settlements and invoices are received for the period to which the RCE applies. PGE expects to defer a significant majority of these costs through its various OPUC approved mechanisms over net variable power costs.

PGE believes it has adequate liquidity to cover the event.

***Power costs*—**Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. As approved by the OPUC, the 2023 AUT included a final increase in power costs for 2023, and a corresponding increase in annual revenue requirement of $186 million from 2022 levels, which were reflected in customer prices effective January 1, 2023. The 2024 AUT contains a $216 million increase in NVPC that will be recovered in customer prices beginning January 1, 2024. For more information regarding the PCAM, see "*Power operations*" within this Overview section of Item 7.

***Portland Harbor Environmental Remediation Account (PHERA) mechanism*—**The EPA has listed PGE as one of over one hundred Potentially Responsible Parties (PRPs) related to the remediation of the Portland Harbor

Superfund site. As of December 31, 2023, significant uncertainties still remained concerning the precise requirements for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. In a Record of Decision (ROD) issued in 2017, the EPA outlined its selected remediation plan for clean-up of the Portland Harbor site, which had an estimated total cost of $1.7 billion. 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 Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of 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 an 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. The impact of such costs to the Company's results of operations is mitigated by the PHERA mechanism. As approved by the OPUC, the recovery mechanism allows the Company to defer and recover estimated liabilities and incurred legal and technical analysis expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, including, but not limited to, insurance recoveries, and customer prices, as necessary. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds, and annual expenditures in excess of $6 million, excluding contingent liabilities, are subject to an annual earnings test. PGE's results of operations may be impacted to the extent such expenditures were to be deemed imprudent by the OPUC or disallowed per the prescribed earnings test. For further information regarding the PHERA mechanism, see *"EPA Investigation of Portland Harbor"* in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data."

***Decoupling*—**The decoupling mechanism, previously authorized by the OPUC through 2022, was intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency, customer-owned generation, and conservation efforts by residential and certain commercial customers. The mechanism provided for collection from (or refund to) customers if weather-adjusted use per customer was less (or more) than that projected in the Company's most recent GRC.

In the 2022 GRC, parties reached an agreement that eliminated PGE's decoupling mechanism upon the effective date of new customer prices that resulted in May 2022. Pursuant to the 2022 GRC Order, the OPUC adopted the agreement such that deferrals would not occur after 2022, although amortization of then previously recorded deferrals was to continue as scheduled until collected or refunded in future customer prices. For the year ended December 31, 2022, with OPUC approval, PGE is collecting $5 million in customer prices over a one-year period that began January 1, 2024. In the 2024 GRC filing, the Company included a concept proposal that could lead to resuming decoupling, with certain modifications. As stipulated in the 2024 GRC settlement agreement, PGE made a tariff filing, on January 26, 2024, that proposes weather-normalized decoupling, which would begin April 1, 2024 and sunset after December 31, 2025, for residential and small non-residential customers. The proposal seeks a 3% annual limit on collections or refunds and a balancing account, which would carry forward to subsequent years for refund or recovery, to capture any amounts that exceed the limit.

***Deferral of Boardman revenue requirement*—**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.

***Renewable recovery framework*—**As previously authorized by the OPUC, the RAC is a primary method available to recover costs associated with renewable resources. The RAC allows PGE to recover prudently incurred costs of renewable resources through filings made each year, outside of a GRC. Under the RAC, during 2023, the Company submitted a filing for Clearwater that went into service January 5, 2024. PGE estimates the requested tariff, to begin June 1, 2024, will result in an overall $28 million reduction in annual revenues, which results from customer credits. The Company plans to defer the revenue requirement between January 5, 2024 and May 31, 2024 for consideration in a future regulatory proceeding.

In the 2019 GRC Order, the OPUC authorized the inclusion of prudent costs of energy storage projects associated with renewables in future RAC filings, under certain conditions.

Operating Activities

In addition to electricity provided by PGE's own generation portfolio, to meet retail load requirements and balance energy supply with customer demand, manage risk, and administer its long-term wholesale contracts, the Company purchases and sells electricity in the wholesale market. PGE also performs portfolio management and wholesale market sales services for third parties in the region. The Company participates in the western EIM, which allows, among other things, more renewable energy integration into the grid by better complementing the variable output of renewable resources. The Company also purchases natural gas in the United States and Canada to fuel its generation portfolio and sells excess gas back into the wholesale market.

PGE generates revenues and cash flows primarily from the sale and distribution of electricity to its retail customers in Oregon. The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. Historically, PGE had experienced its highest MWa deliveries and retail energy sales during the winter heating season and recorded its current winter peak load in December 2022. Summer peak deliveries have continued to exceed those of the winter months for several years, generally resulting from air conditioning demand and the trend toward a warmer overall climate. During the summer of 2023, demand reached a new all-time high, surpassing the previous mark, which was set in 2021. For further information regarding seasonal fluctuations, see *"Seasonality"* in the Customers and Revenues section in Item 1.—"Business." Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues. Wholesale power availability and price, hydro and wind generation, and fuel costs for thermal plants can also affect income from operations. PGE has taken measures to enhance the availability of supply chain-constrained items that are needed to serve new and existing customers, such as advance ordering of critical materials, pre-securing manufacturing capacity with strategic partners, and evaluating availability with established and new suppliers. PGE has also taken measures to help mitigate cost increases through long term agreements, supplier engagement and expanding the supply base.

Customers and demand—The following tables present total energy deliveries and the average number of retail customers by type for 2023 and 2022.

Energy deliveries (MWh in thousands)	2023	2022	% Increase/ (Decrease)
Retail:			
Residential	7,952	8,088	(1.7)%
Commercial (PGE sales only)	6,601	6,650	(0.7)
Direct Access	577	548	5.3
Total Commercial	7,178	7,198	(0.3)
Industrial (PGE sales only)	4,578	4,167	9.9
Direct Access	1,715	1,778	(3.5)
Total Industrial	6,293	5,945	5.9
Total (PGE sales only)	19,131	18,905	1.2
Total Direct Access	2,292	2,326	(1.5)
Total retail energy deliveries	21,423	21,231	0.9 %
Wholesale energy deliveries	6,950	6,000	15.8
Total energy deliveries	28,373	27,231	4.2 %

Average number of retail customers	2023		2022		% Increase/ (Decrease)
Residential	815,920	88 %	809,573	88 %	0.8 %
Commercial	112,204	12	112,127	12	0.1
Industrial	196	—	192	—	2.1
Direct access	540	—	552	—	(2.2)
Total	928,860	100 %	922,444	100 %	0.7 %

In 2023, retail energy deliveries increased 0.9% from 2022, with increases in demand from industrial customers outweighing the decreases seen in the residential and commercial classes. The industrial class has experienced an increase in energy deliveries, due primarily to continued growth in the high-tech and digital services sectors. Compared to the prior year, weather had a negative impact on deliveries, as warm weather in the fourth quarter more than offset cooler temperatures early in the year. In 2022, PGE began to see decreases in average residential usage on a weather-adjusted, year over year basis, however expects that the shift that has occurred with respect to hybrid work schedules will have lasting impacts on average usage.

Residential energy deliveries, which are most sensitive to fluctuations in temperatures, were 1.7% lower in 2023 than 2022, due to a 2.5% decrease in average usage per customer, which resulted largely from warmer fourth quarter temperatures, and was partially offset by an 0.8% increase in the average number of customers.

Commercial energy deliveries were fairly stable in 2023 with the prior year, showing a decrease of 0.3%. While COVID-19 related recovery has largely occurred, continued impacts of programmatic energy efficiency and uncertainty in economic conditions have tempered commercial growth in 2023.

Industrial energy deliveries increased 5.9% in 2023 due to continued strength in the high-tech manufacturing and digital service sector. Several large customers experienced continued growth in 2023 and new data center facilities came online.

Total heating degree-days, an indication of electricity use for heating, declined 6% in 2023 from 2022 in total, and was 6% below the 15-year moving average. However, while 2023 began with low temperatures and high seasonal heating demand, that pattern reversed in the second quarter as heating degree-days fell below prior year and seasonal averages. Correspondingly, cooling degree-days, a similar indication of the extent to which customers were likely to have used electricity for cooling, exceeded the 15-year average by 50%, although were only 4% above the 2022 total, illustrating that the two most recent summer seasons have been exceedingly warm compared to historical averages. The Company experienced a new record winter peak load in December 2022 of 4,113 MW and a new summer peak in August 2023 of 4,498 MW. The warm temperatures persisted through the balance of the year, with actual temperatures in the fourth quarter, which is normally a high heating demand period, being among the warmest ever recorded.

The following table presents the number of heating and cooling degree-days in 2023 and 2022, along with the current 15-year averages, reflecting the influence that weather had on comparative energy deliveries.

	Heating Degree-Days			Cooling Degree-Days		
	2023	2022	15-Year Average	2023	2022	15-Year Average
1st quarter	1,927	1,761	1,840	—	—	—
2nd quarter	554	760	628	195	75	101
3rd quarter	45	6	65	687	745	493
4th quarter	1,319	1,576	1,552	16	45	5
Total	3,845	4,103	4,085	898	865	599
Increase (decrease) from the 15-year average	(6)%	— %		50 %	44 %	

On a weather-adjusted basis, total retail deliveries increased 1.4 % from 2022. The increase was driven by a 5.9% growth in industrial deliveries, partially offset by a 0.2% decline in commercial energy deliveries and a 0.5% decrease in weather-adjusted deliveries to residential customers, as average use per customer has declined from the highs seen during the first two years of the COVID-19 pandemic. The Company projects that retail energy deliveries for 2024 will be between 2% and 3% above 2023 weather-adjusted levels, reflecting continued growth in industrial deliveries.

ESSs supplied Direct Access customers with energy representing 11% of PGE’s total retail energy deliveries during 2023 and 2022. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs represent 12% of the Company’s total retail energy deliveries for 2023. With the adoption of the New Large Load Direct Access program in 2020, as much as 17% of the Company’s 2023 energy deliveries could have been supplied by ESSs.

Power operations—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of, and obtain reasonably-priced power for, its retail customers, manage risk, and administer its long-term wholesale contracts. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. PGE also purchases wholesale natural gas in the United States and Canada to fuel its generating portfolio and sells excess gas back into the wholesale market. As a result, the amount of power generated and purchased in the wholesale market to meet the Company’s retail load requirement can vary from period to period and impacts NVPC and income from operations.

The following table provides information regarding the performance of the Company’s generation portfolio.

	Plant availability (1)		Actual energy provided compared to projected levels (2)		Actual energy provided as a percentage of total retail load	
	2023	2022	2023	2022	2023	2022
Thermal:						
Natural gas	85 %	86 %	99 %	81 %	54 %	41 %
Coal (3)	90	89	99	100	11	11
Wind (4)	98	82	88	81	9	9
Hydro	89	94	69	81	6	5

(1) Plant availability represents the percentage of the year plants were available for operations, which is impacted by planned maintenance and forced, or unplanned, outages.
(2) Projected levels of energy are included as part of PGE's AUT. Such projections establish the power cost component of retail prices for the following calendar year. Any shortfall is generally replaced with power from higher cost sources, while any excess generally displaces power from higher cost sources.
(3) Plant availability reflects Colstrip, which PGE does not operate.
(4) Plant availability includes Wheatridge, which PGE does not operate.

Energy received from PGE-owned and jointly-owned thermal plants in 2023 compared to 2022 increased by 27%. This increase is primarily driven by economic dispatch decisions and to replace shortfalls from hydro and wind resources. Energy expected to be received from thermal resources is projected annually in the AUT based on forecast market prices, variable costs to run the plant, and the constraints of the plant. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year.

Total energy received from all hydroelectric sources, both PGE-owned generation and purchased, decreased 21% in 2023 compared to 2022 primarily due to less favorable hydro conditions in the current period. Energy purchased from mid-Columbia and other regional hydroelectric projects decreased 26% while energy generated by the Company-owned facilities increased 11% in 2023. Energy expected to be received from hydroelectric resources is projected annually in the AUT based on a modified hydro study, which utilizes 80 years of historical stream flow data. For further detail on regional hydro results, see *"Purchased power and fuel"* in the Results of Operations section in this Item 7.

Energy received from PGE-owned wind resources and under contracts increased 7% in 2023 compared to 2022. While 2023 saw less favorable wind conditions, unplanned plant outages in 2022 that did not reoccur resulted in the overall net increase year over year. Energy expected to be received from wind generating resources is projected annually in the AUT based on historical generation. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available.

Under the PCAM, PGE may share with customers a portion of cost variances associated with NVPC. Customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year, if such differences exceed a prescribed "deadband" limit, 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. The following is a summary of the results of the Company's PCAM as calculated for regulatory purposes for 2023 and 2022:

- For 2023, actual NVPC was above baseline NVPC by $5 million, which was within the established deadband range. Accordingly, 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 2022, actual NVPC was above baseline NVPC by $23 million, which was within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2022.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

The results of operations are as follows for the years presented (dollars in millions):

	Years Ended December 31, 2023 Amount	2022 Amount	% Increase (Decrease)
Total revenues	$ 2,923	$ 2,647	10 %
Operating expenses:			
Purchased power and fuel	1,190	988	20
Generation, transmission and distribution	374	348	7
Administrative and other	341	340	—
Depreciation and amortization	458	417	10
Taxes other than income taxes	164	157	4
Total operating expenses	2,527	2,250	12
Income from operations	396	397	—
Interest expense, net *	173	156	11
Other income:			
Allowance for equity funds used during construction	19	14	36
Miscellaneous income, net	31	17	82
Other income, net	50	31	61
Income before income taxes	273	272	—
Income tax expense	45	39	15
Net income	$ 228	$ 233	(2)%

* Includes an allowance for borrowed funds used during construction of $13 million in 2023 and $7 million in 2022.

2023 Compared to 2022

Net income for 2023 decreased $5 million from 2022. In 2023, higher Purchased power and fuel costs more than offset increases in Retail revenues authorized by the OPUC in the AUT in anticipation of higher NVPC. Retail revenues also increased due to an overall increase in deliveries, although that demand impact was more than offset by the average price result of the relative mix of deliveries among customer classes. Warm temperatures in the latter portion of 2023 suppressed demand from residential customers while the industrial class continued to show strength. The impact of higher natural gas and electricity prices coupled with increased customer demand added upward pressure on Purchased power and fuel expense. Wholesale sales increased, driven largely by economic dispatch decisions and portfolio positions, which contributed to reducing NVPC. Operating expenses reflect the additional charges that resulted from the amortization of prior deferrals, vegetation management and wildfire mitigation efforts, and increased run hours at generation facilities in 2023.The increase in Depreciation and amortization reflect higher utility plant balances and charges resulting from prior regulatory deferrals. Interest expense rose primarily due to higher long-term debt and outstanding commercial paper balances. Other income was up due to favorable market changes on the non-qualified benefit trust, higher AFUDC equity income driven by higher construction work-in-progress balances in 2023, the recognition of previously deferred equity interest income in conjunction with amortization of regulatory deferrals that began in 2023, and higher other regulatory interest income, all of which was partially offset by a prior year settlement gain on a benefit plan.

Total revenues consist of the following for the years presented (in millions):

	2023	2022	% Increase (Decrease)
Retail:			
Residential	$ 1,263	$ 1,158	9 %
Commercial	800	723	11
Industrial	349	289	21
Subtotal	2,412	2,170	11
Direct Access:			
Commercial	8	12	(33)
Industrial	19	23	(17)
Subtotal	27	35	(23)
Subtotal Retail	2,439	2,205	11
Alternative revenue programs, net of amortization	11	11	—
Other accrued (deferred) revenues, net	(3)	7	(143)
Total retail revenues	2,447	2,223	10
Wholesale revenues	418	363	15
Other operating revenues	58	61	(5)
Total revenues	$ 2,923	$ 2,647	10 %

Total retail revenues—The following items contributed to the increase in Total retail revenues for the year ended December 31, 2023 compared to the year ended December 31, 2022 (dollars in millions):

Year ended December 31, 2022	$	2,223
Change in prices as a result of the AUT, approved by the OPUC (partially offset in Purchased power and fuel)		186
Recovery of deferrals for 2020 Labor Day wildfire and 2021 ice storm		26
Retail energy deliveries driven by changes in customer load		18
PCAM collection, offset in Purchased power and fuel expense		14
Wildfire mitigation revenue (offset in Generation, transmission and distribution)		12
Colstrip depreciation life adjustment (offset in Depreciation and amortization expense)		9
Boardman settlement refund, net of amortization		(5)
Average price of energy deliveries due primarily to the relative mix of deliveries among customer classes		(44)
Combination of various supplemental tariffs and adjustments		8
Year ended December 31, 2023		2,447
Change in Total retail revenues	$	224

Wholesale revenues result from sales of electricity to utilities and power marketers made in the Company's efforts to meet the needs of, and secure reasonably priced power for, its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2023, a $55 million, or 15%, increase from 2022 in wholesale revenues occurred as sales volumes increased 16%, which resulted in a $57 million increase. Partly offsetting that increase was a $2 million decrease in average prices received when the Company sold power into the wholesale market. Elevated sales prices continued during 2023 and have resulted from several factors, including reduced hydro generation in the region, the economic recovery, strong demand, and ongoing capacity limitations in the region.

Other operating revenues decreased $3 million, or 5%, in 2023 from 2022, primarily as a result of market conditions in 2022 that allowed the Company to sell natural gas in excess of amounts needed for the Company's generation portfolio back into the wholesale market at gains that have exceeded those experienced during 2023.

Purchased power and fuel expense includes 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.

The following items contributed to the increase in Purchased power and fuel for the year ended December 31, 2023 compared to the year ended December 31, 2022 (dollars in millions, except for average variable power cost per MWh):

Year ended December 31, 2022	$	988
Average variable power cost per MWh		278
Total system load		(91)
2021 PCAM deferral amortization		15
Year ended December 31, 2023		1,190
Change in Purchased power and fuel	$	202
Average variable power cost per MWh:		
Year ended December 31, 2022	$	37.71
Year ended December 31, 2023	$	43.26
Total system load (MWh in thousands):		
Year ended December 31, 2022		26,215
Year ended December 31, 2023		27,169

For the year ended December 31, 2023, the $278 million increase related to the change in average variable power cost per MWh was primarily driven by a 17% increase in the average cost for purchased power, and a 77% increase in the average cost of power from the Company's own generation, driven primarily by the settlement of physical and financial gas contracts. The $91 million decrease related to total system load was primarily due to the change in mix of sources of energy with purchased power declining 16% resulting in a $131 million decrease, offset by a 23% increase in energy obtained from PGE's own generation resulting in a $40 million increase.

PGE's sources of energy, total system load, and retail load requirement for the years presented are as follows:

	Years Ended December 31,			
	2023		2022	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Natural gas	10,981	40 %	8,242	31 %
Coal	2,214	8	2,186	8
Total thermal	13,195	48	10,428	39
Hydro	1,144	4	1,027	4
Wind	1,918	7	1,765	7
Total generation	16,257	59	13,220	50
Purchased power:				
Hydro	4,646	17	6,297	24
Wind	846	3	824	3
Solar	1,055	4	723	3
Natural Gas	184	1	33	—
Waste, Wood and Landfill Gas	163	1	168	1
Source not specified	4,018	15	4,961	19
Total purchased power	10,912	41	13,006	50
Total system load	27,169	100 %	26,226	100 %
Less: wholesale sales	(6,950)		(6,000)	
Retail load requirement	20,219		20,226	

Purchased power in the table above includes power received from qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA) as follows:

	Years Ended December 31, 2023	2022
Sources of energy (MWhs in thousands):		
PURPA purchased power:		
Hydro	28	36
Wind	25	25
Solar	592	588
Waste, Wood, Landfill Gas, and Other	114	101
Total	759	750

The following table presents the forecasted April-to-September 2024 and actual April-to-September 2023 and 2022 runoff at particular points of major rivers relevant to PGE's hydro resources:

	Runoff as a Percent of Normal*		
Location	2024 Forecast	2023 Actual	2022 Actual
Columbia River at The Dalles, Oregon	81 %	83 %	107 %
Mid-Columbia River at Grand Coulee, Washington	79	79	110
Clackamas River at Estacada, Oregon	92	101	139
Deschutes River at Moody, Oregon	99	98	92

* Volumetric water supply forecasts and historical averages for the Pacific Northwest region are prepared by the Northwest River Forecast Center, with the Natural Resources Conservation Service and other cooperating agencies.

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, increased $147 million in 2023 compared with 2022. The increase attributable to changes in Purchased power and fuel expense was the result of a 15% increase in the average variable power cost per MWh and a 4% increase in total system load. The increase in actual NVPC was also a result of the 1% lower average price per MWh sold and a 16% increase in the volume of wholesale energy deliveries.

The following items contributed to the increase in Actual NVPC for the year ended December 31, 2023 compared to the year ended December 31, 2022 (in millions):

Year ended December 31, 2022	$ 626
Purchased power and fuel expense	187
Wholesale revenues	(55)
2021 PCAM deferral amortization	15
Year ended December 31, 2023	773
Change in NVPC	$ 147

For further information regarding NVPC in relation to the PCAM, see *"Power operations"* in the Overview section of this Item 7.

Generation, transmission and distribution expense increased $26 million or 7% for the year ended December 31, 2023 compared to the year ended December 31, 2022, with the change attributed largely to the following items (in millions):

Year ended December 31, 2022	$	348
Amortizations of previously deferred 2020 wildfire and 2021 ice storm costs		18
Higher vegetation management, inspection, wildfire mitigation, and distribution maintenance expenses		15
Increase in generation facility maintenance expenses driven by major maintenance activities and increased run hours		13
Lower service restoration and storm response costs		(7)
Release of deferred amounts pursuant to earnings test in 2022		(16)
Miscellaneous expenses		3
Year ended December 31, 2023		374
Change in Generation, transmission and distribution	$	26

Administrative and other expense increased $1 million for the year ended December 31, 2023 compared to the year ended December 31, 2022 due largely to the following items (in millions):

Year ended December 31, 2022	$	340
Amortization of COVID-19 bad debt expense deferral		9
Regulatory program amortization		3
Lower employee compensation and benefits expenses		(4)
Lower professional service expenses		(8)
Miscellaneous expenses		1
Year ended December 31, 2023		341
Change in Administrative and other	$	1

PGE commenced amortization of previously deferred COVID-19 related bad debt expenses on April 1, 2023. PGE amortized $9 million of COVID-19 related bad debt expense for the twelve months ended December 31, 2023. See Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements," for more information.

Depreciation and amortization expense increased $41 million or 10% for the year ended December 31, 2023 compared to year ended December 31, 2022, with the change largely resulting from the following items (in millions):

Year ended December 31, 2022	$	417
Capital additions		20
Activity related to regulatory programs (offset elsewhere on the income statement)		13
Accelerated depreciation of the Colstrip facility as approved by the OPUC's 2022 GRC Order		9
Miscellaneous expenses		(1)
Year ended December 31, 2023		458
Change in Depreciation and amortization	$	41

Taxes other than income taxes expense increased $7 million, or 4%, in 2023 compared with 2022, primarily due to higher franchise fees and property tax expenses.

Interest expense increased $17 million, or 11%, in 2023 compared with 2022 driven by higher average balances of outstanding debt, partially offset by higher AFUDC debt income driven by higher construction work-in-progress balances in 2023.

Other income, net increased $19 million, or 61%, in 2023 compared to 2022. The increase was primarily attributable to $11 million in favorable market changes on the non-qualified benefit trust, $11 million in higher regulatory interest income, and $6 million higher AFUDC equity income driven by higher construction work-in-progress balances in 2023.

The increase was partially offset by the execution of a buyout of the Non-represented Retiree Medical Plan in 2022, resulting in a $11 million settlement gain. For more information, see Note 11, Employee Benefits, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplemental Data."

Income tax expense increased $6 million, or 15%, in 2023 compared to 2022 primarily driven by lower research and development tax credit benefits. The increase was partially offset by lower expenses from flow-through items.

2022 Compared to 2021

For a comparison of the Company's results of operations for the fiscal year ended December 31, 2022 to the year ended December 31, 2021, see Item 7.—" Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2022, filed with the SEC on February 16, 2023.

Liquidity and Capital Resources

Discussions, forward-looking statements, and projections in this section, and similar statements in other parts of this Annual Report on Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan." in Item 1A.—"Risk Factors," for further information.

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2023 and projected capital expenditures and future debt maturities for 2024 through 2028 (in millions, excluding AFUDC):

	Years Ending December 31,					
	2023	2024	2025	2026	2027	2028
Ongoing capital expenditures [1]	$ 792	$ 895	$ 865	$ 895	$ 890	$ 920
Transmission	144	170	180	255	265	435
Clearwater Wind Development	$ 405	$ 10	$ —	$ —	$ —	$ —
BESS projects	$ 121	$ 235	$ 155	$ —	$ —	$ —
Total capital expenditures [2]	$ 1,462	$ 1,310	$ 1,200	$ 1,150	$ 1,155	$ 1,355
Long-term debt maturities	$ 260	$ 80	$ —	$ —	$ 160	$ 100

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects. Includes accrued capital additions, preliminary engineering, removal costs, and certain intangible working capital assets.
(2) Amounts subsequent to 2023 are estimates as of the date of this report and may be affected by economic conditions, including but not limited to, impacts of inflation, changes to the cost of materials and labor, and financing costs.

During 2023, PGE funded its capital expenditures through a combination of cash from operations in the amount of $420 million, proceeds from the issuance of FMBs in the total amount of $600 million, and net proceeds from the issuance of shares pursuant to the equity forward sale agreement (EFSA) of $485 million. Capital expenditures in 2024 are expected to be approximately $1.3 billion. PGE plans to fund the 2024 capital expenditures with cash from operations during 2024, which is expected to range from $700 million to $800 million, the issuance of debt securities of up to $730 million, issuances of shares pursuant to the at the market offering program, and the issuance of commercial paper, as needed. The actual timing and amount of any other issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures. For a discussion concerning PGE's ability to fund its future capital requirements, see "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, information technology systems, and debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

The following summarizes PGE's cash flows for the periods presented (in millions):

	Years Ended December 31,	
	2023	2022
Cash and cash equivalents, beginning of year	$ 165	$ 52
Net cash provided by (used in):		
Operating activities	420	674
Investing activities	(1,358)	(758)
Financing activities	778	197
Net change in cash and cash equivalents	(160)	113
Cash and cash equivalents, end of year	$ 5	$ 165

2023 Compared to 2022

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The following items contributed to the net change in cash flows from operations for 2023 compared to 2022 (dollars in millions):

	Increase/ (Decrease)
Net income	$ (5)
Accounts receivable and unbilled revenue	37
Margin deposit activity	(113)
Accounts payable	(323)
Regulatory deferral activity	85
Depreciation and amortization	41
Proceeds from tax credit sales	24
Net change in cash flow from operations	$ (254)

For the year ended December 31, 2023, operating cash flows were significantly impacted by changes in working capital from December 31, 2022, primarily related to Accounts payable for purchased power and fuel costs and related margin deposits activity. In December 2022, PGE experienced elevated natural gas and power prices due to volatility in the wholesale markets, which led to increased cash used in operating activities for 2023 as cash payments for physical commodity purchases and related margin activity were made.

For additional information regarding changes in Net income, see the Results of Operations section in this Item 7.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2024 will range from $475 million to $525 million. Combined with all other sources, cash provided by operations in 2024 is estimated to range from $700 million to $800 million.

Cash provided by operations includes the recovery in customer prices of cash charges related to various long-term contractual obligations such as interest on long-term debt and purchased power and fuel contracts. PGE's anticipated employer contributions for its defined benefit pension plan and other postretirement plans is $29 million in 2024, $24 million in 2025, 2026, and in 2027, and $23 million in 2028. Contributions are expected to be covered by cash provided by operations. For additional information regarding contractual obligations, see Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's generation, transmission, and distribution facilities. The $600 million increase in net cash used in investing activities in 2023 compared with 2022 is primarily due to capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities, which increased $592 million due primarily to the Clearwater Wind and BESS projects, as well as an $11 million increase related to proceeds from the sale of property in 2022 that did not recur.

The Company plans for $1.3 billion of capital expenditures in 2024 related to upgrades to and replacement of generation, transmission, and distribution infrastructure as well as costs related to BESS projects. PGE plans to fund the 2024 capital expenditures with cash from operations during 2024, as discussed above, as well as with the issuance of debt, issuances of shares pursuant to the at the market offering program, and short-term debt as necessary. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2023, cash provided by financing activities was primarily the result of $485 million in proceeds from the issuance of common stock pursuant to the EFSA, funding of $600 million in FMBs, and $146 million due to the issuance of commercial paper. This was partially offset by a $260 million repayment of a term loan and payment of dividends in the amount of $179 million.

2022 Compared to 2021

For a comparison of liquidity and capital resources and the Company's cash flow activities for the fiscal year ended December 31, 2022 and 2021, see Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2022, which was filed with the SEC on February 16, 2023.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

	Moody's	S&P
First Mortgage Bonds	A1	A
Senior unsecured debt	A3	BBB+
Commercial paper	P-2	A-2
Outlook	Stable	Stable

In the event Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to higher fees on its revolving credit facility. The Company could also be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheets, while any letters of credit issued are not reflected in the Company's consolidated balance sheets.

As of December 31, 2023, PGE had posted $132 million of collateral with these counterparties, consisting of $92 million in cash and $40 million in bank letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2023, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $76 million and decreases to $60 million by December 31, 2024 and $10 million by December 31, 2025. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade as of December 31, 2023 is $204 million and decreases to $188 million by December 31, 2024 and $82 million by December 31, 2025.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit facilities would increase.

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. The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2023, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $602 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt to total capital ratio). As of December 31, 2023, the Company's debt to total capital ratio, as calculated under the credit agreements, was 56.2%.

Debt and Equity Financings

PGE's ability to secure sufficient short- and long-term capital at a reasonable cost is determined by its financial performance and outlook, credit ratings, capital expenditure requirements, alternatives available to investors, market conditions, and other factors, such as the volatility in the capital markets in response to inflationary pressures and interest rate increases by the federal reserve. Management believes that the availability of its revolving credit facility, the expected ability to issue short- and long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future.

Short-term Debt—Pursuant to an order issued by the FERC on January 18, 2024, PGE has authorization to issue short-term debt up to a total of $900 million through February 6, 2026. The following table shows available liquidity as of December 31, 2023 (in millions):

	December 31, 2023		
	Capacity	Outstanding	Available
Revolving credit facility [1]	$ 750	$ —	$ 750
Letters of credit [2]	320	106	214
Total credit	$ 1,070	$ 106	964
Cash and cash equivalents			5
Total liquidity			$ 969

(1) Scheduled to expire September 2028. PGE has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay outstanding commercial paper. As of December 31, 2023, PGE had $146 million of commercial paper outstanding, therefore, the elected available credit capacity is $604 million.

(2) PGE has four letter of credit facilities under which the Company can request letters of credit for an original term not to exceed one year.

As of December 31, 2023, PGE had a $750 million unsecured revolving credit facility scheduled to expire in September 2028. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% of the facility approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. 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. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and to provide cash for general corporate purposes. 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 Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility. 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 of commercial paper outstanding.

PGE typically classifies borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2023, PGE had no borrowings, and no letters of credit issued. As a result, as of December 31, 2023, 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.

In addition, PGE has four letter of credit facilities under which the Company has total capacity of $320 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, which are considered off-balance sheet arrangements, letters of credit for a total of $106 million were outstanding as of December 31, 2023. PGE works to optimize its use of its letter of credit facility to manage energy trading margin.

Long-term Debt—During 2023, PGE issued and funded a total of $600 million of FMBs.

In August 2023, PGE entered into a Bond Purchase Agreement related to the sale of $500 million in 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), $100 million of which was issued under PGE's Green Financing Framework. The first half of FMBs funded in 2022 and the remaining $100 million funded in full on January 13, 2023.

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.

As of December 31, 2023, total long-term debt outstanding, net of $14 million of unamortized debt expense, was $3,985 million, of which $80 million is scheduled to mature in 2024.

Equity—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 counterparty 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.

In 2022, PGE entered into an EFSA in connection with the public offering of 10,100,000 shares of its common stock. Effective October 28, 2022, pursuant to the terms of the EFSA, the forward counterparties borrowed 11,615,000 shares of PGE's common stock with an initial value of $499 million, 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. PGE receives proceeds from the sale of the common stock when the EFSA is physically settled. 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.

For additional information on the EFSA, see Note 13, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Capital Structure—PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including current debt maturities and excluding lease obligations) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade debt ratings and provides access to long-term capital at favorable interest rates. The Company's common equity ratio was 44.6% and 43.3% as of December 31, 2023 and 2022, respectively.

Critical Accounting Policies and Estimates

The preparation of consolidated financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE applies regulatory accounting, which includes the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators, prices are designed to recover the specific enterprise's cost-of-service, and, 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. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets is not probable, PGE would expense such items in the period such determination is made. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

For additional information on PGE's regulatory assets and liabilities, see "*Regulatory Matters*" in the Overview section in this Item 7., and Note 7, Regulatory Assets and Liabilities in Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Asset Retirement Obligations

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Estimates for ARO liabilities are generally based on site-specific studies and are periodically subject to updates and changes that may arise over time.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. For revisions to ARO liabilities in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Accretion of the ARO liability is classified as Depreciation and amortization expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

As a co-owner of Colstrip, PGE has provided surety bonds, which are considered off-balance sheet arrangements, of $21 million as of December 31, 2023 on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Station, Colstrip Montana (the AOC) as required by the Montana Department of Environmental Quality. It is possible that each co-owner of Colstrip will be required, at some future point, to post additional financial assurance to support further performance by the operator of closure and remediation actions under the AOC.

For additional information on AROs, see Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency and the reasons to the effect that it cannot be reasonably estimated are disclosed. 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. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

For additional information on contingencies, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations, or cash flows, as discussed below.

Energy Risk Management

PGE has an Executive Risk Committee (ERC) whose primary purpose is to oversee, guide, and support the prudent management of the Company's risks, as well as review and recommend energy portfolio risk limits that are subject to approval by the Audit and Risk Committee of the PGE Board of Directors. The ERC's responsibilities include risk reporting to provide visibility into portfolio risk and manage alignment with the Company's risk strategy and tolerances, providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market, liquidity and credit risk management related to the Company's energy portfolio management activities. The ERC consists of officers and Company representatives with responsibility for risk management, finance and accounting, information technology, utility operations, legal, and rates and regulatory affairs.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase and sale contracts to supplement its own generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company's natural gas- and coal-fired generating plants, and the sale of natural gas in excess of amounts needed for the Company's natural gas-fired generating plants.

These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as: i) forward contracts, which may involve physical delivery of an energy commodity; ii) financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and iii) option contracts to mitigate risk that arises from market fluctuations of commodity prices. The Company does not intend to engage in trading activities for non-retail purposes.

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 reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. Energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel or Revenues, net in the statements of income and expected to be included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE employs a hedging strategy to mitigate its exposure to fluctuations in the Canadian exchange rate.

As of December 31, 2023, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2023, PGE had no borrowings outstanding under its revolving credit facility and $146 million commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as deemed necessary.

As of December 31, 2023, the total fair value and carrying amounts, excluding unamortized debt expense, by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date						
		Total	2024	2025	2026	2027	2028	There-after
First Mortgage Bonds	$ 3,598	$ 3,880	$ 80	$ —	$ —	$ 160	$ 100	$ 3,540
Pollution Control Revenue Bonds	107	119	—	—	—	—	—	119
Total	$ 3,705	$ 3,999	$ 80	$ —	$ —	$ 160	$ 100	$ 3,659

As of December 31, 2023, PGE had no long-term debt instruments subject to interest rate risk exposures

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by 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.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, within certain limits, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimates are used to provide an allowance for uncollectible accounts receivable related to retail sales to address such risk.

As of December 31, 2023, PGE's credit risk exposure is $50 million for commodity activities, of which $15 million is with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature from 2023 to 2025. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade counterparties include those with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit, and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington. These contracts currently provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public utility districts*" in Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Portland General Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2023, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting — Refer to Notes 2 and 7 to the consolidated financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Oregon (the "OPUC"), which has jurisdiction with respect to the rates for retail electricity in the state of Oregon, and to wholesale rate regulation by the Federal Energy Regulatory Commission (the "FERC"). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts certain financial statement line items and disclosures.

The Company's rates are subject to regulatory rate-setting processes and annual earnings oversight. Because the OPUC and the FERC set the rates the Company is allowed to charge customers based on allowable costs, including a reasonable return on equity, the Company applies accounting standards that require the financial statements to reflect the effects of rate regulation. The Company's rates for retail customers are determined and approved in regulatory proceedings based on an analysis of the Company's cost of providing service to retail customers. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard. The Company assesses whether the regulatory assets and regulatory liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs, and factors such as changes in applicable regulatory and political environments. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the OPUC and the FERC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to its pervasive impact on the Company's financial statements and the significant judgments made by management to support its assertions about certain account balances and disclosures. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the OPUC or FERC, including decisions regarding the prudency of costs which have been deferred as regulatory assets, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities and significant auditor judgment to evaluate management estimates and the subjectivity of audit evidence.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the OPUC included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as electric utility plant; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the OPUC and the FERC for the Company, filings made by intervenors, regulatory statutes, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the OPUC's and the FERC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process, we inspected the Company's filings with the OPUC and the FERC, and considered the filings with the OPUC and FERC by intervenors that may impact the Company's future rates, for any evidence that might contradict management's assertions.
- We obtained an analysis from management and support from internal and external legal counsel, as appropriate, regarding probability of recovery for electric utility plant and regulatory assets or future reduction in rates for regulatory liabilities, not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 20, 2024

We have served as the Company's auditor since 2004.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2023	2022	2021
Revenues:			
Revenues, net	$ 2,912	$ 2,636	$ 2,425
Alternative revenue programs, net of amortization	11	11	(29)
Total Revenues	2,923	2,647	2,396
Operating expenses:			
Purchased power and fuel	1,190	988	822
Generation, transmission and distribution	374	348	310
Administrative and other	341	340	336
Depreciation and amortization	458	417	404
Taxes other than income taxes	164	157	146
Total operating expenses	2,527	2,250	2,018
Income from operations	396	397	378
Interest expense, net	173	156	137
Other income:			
Allowance for equity funds used during construction	19	14	17
Miscellaneous income, net	31	17	9
Other income, net	50	31	26
Income before income taxes	273	272	267
Income tax expense	45	39	23
Net income	$ 228	$ 233	$ 244
Weighted-average shares outstanding (in thousands):			
Basic	97,760	89,290	89,481
Diluted	97,952	89,643	89,627
Earnings per share:			
Basic	$ 2.33	$ 2.61	$ 2.72
Diluted	$ 2.33	$ 2.60	$ 2.72

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Years Ended December 31,		
	2023	2022	2021
Net income	$ 228	$ 233	$ 244
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in all three years	(1)	6	1
Comprehensive income	$ 227	$ 239	$ 245

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31,	
	2023	2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5	$ 165
Accounts receivable, net	414	398
Inventories, at average cost:		
Materials and supplies	83	63
Fuel	30	32
Regulatory assets—current	221	54
Other current assets	182	498
Total current assets	935	1,210
Electric utility plant:		
In service	13,329	12,421
Accumulated depreciation and amortization	(4,757)	(4,423)
In service, net	8,572	7,998
Construction work-in-progress	974	467
Electric utility plant, net	9,546	8,465
Regulatory assets—noncurrent	492	473
Nuclear decommissioning trust	31	39
Non-qualified benefit plan trust	35	38
Other noncurrent assets	169	234
Total assets	$ 11,208	$ 10,459

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued

(In millions, except share amounts)

	As of December 31, 2023	As of December 31, 2022
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 347	$ 457
Liabilities from price risk management activities—current	164	118
Short-term debt	146	—
Current portion of long-term debt	80	260
Current portion of finance lease obligations	20	20
Accrued expenses and other current liabilities	355	641
Total current liabilities	1,112	1,496
Long-term debt, net of current portion	3,905	3,386
Regulatory liabilities—noncurrent	1,398	1,389
Deferred income taxes	488	439
Unfunded status of pension and postretirement plans	172	170
Liabilities from price risk management activities—noncurrent	75	75
Asset retirement obligations	272	257
Non-qualified benefit plan liabilities	79	83
Finance lease obligations, net of current portion	289	294
Other noncurrent liabilities	99	91
Total liabilities	7,889	7,680
Commitments and contingencies (see notes)		
Shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 101,159,609 and 89,283,353 shares issued and outstanding as of December 31, 2023 and 2022, respectively	1,750	1,249
Accumulated other comprehensive loss	(5)	(4)
Retained earnings	1,574	1,534
Total shareholders' equity	3,319	2,779
Total liabilities and shareholders' equity	$ 11,208	$ 10,459

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In millions, except share and per share amounts)

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balance as of December 31, 2020	89,537,331	$ 1,231	$ (11)	$ 1,393	$ 2,613
Shares issued pursuant to equity-based plans	123,281	—	—	—	—
Stock-based compensation	—	13	—	—	13
Repurchase of common stock	(250,000)	(3)		(9)	(12)
Dividends declared ($1.6975 per share)	—	—	—	(152)	(152)
Net income	—	—	—	244	244
Other comprehensive income	—	—	1	—	1
Balance as of December 31, 2021	89,410,612	1,241	(10)	1,476	2,707
Shares issued pursuant to equity-based plans	222,741	2	—	—	2
Stock-based compensation	—	11	—	—	11
Repurchase of common stock	(350,000)	(5)		(13)	(18)
Dividends declared ($1.7875 per share)	—	—	—	(162)	(162)
Net income	—	—	—	233	233
Other comprehensive income	—	—	6	—	6
Balance as of December 31, 2022	89,283,353	1,249	(4)	1,534	2,779
Issuance of shares pursuant to equity forward sales agreement	11,615,000	485	—	—	485
Shares issued pursuant to equity-based plans	261,256	3	—	—	3
Stock-based compensation	—	13	—	—	13
Dividends declared ($1.8775 per share)	—	—	—	(188)	(188)
Net income	—	—	—	228	228
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2023	101,159,609	$ 1,750	$ (5)	$ 1,574	$ 3,319

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years Ended December 31,		
	2023	2022	2021
Cash flows from operating activities:			
Net income	$ 228	$ 233	$ 244
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	458	417	404
Deferred income taxes	8	6	5
Allowance for equity funds used during construction	(19)	(14)	(17)
Pension and other postretirement benefits	5	13	24
Decoupling mechanism deferrals, net of amortization	(11)	(11)	29
Stock-based compensation	17	15	14
Regulatory assets	20	(46)	(158)
Regulatory liabilities	24	5	7
Tax credit sales	24	—	—
Other non-cash income and expenses, net	40	40	23
Changes in working capital:			
Accounts receivable and unbilled revenues	(29)	(66)	(64)
Margin deposits	24	(80)	(29)
Accounts payable and accrued liabilities	(166)	157	61
Margin deposits from wholesale counterparties	(135)	82	58
Other working capital items, net	(20)	(22)	(21)
Contribution to non-qualified employee benefit trust	(7)	(9)	(11)
Asset retirement obligation settlements	(25)	(27)	(18)
Other, net	(16)	(19)	(19)
Net cash provided by operating activities	420	674	532
Cash flows from investing activities:			
Capital expenditures	(1,358)	(766)	(636)
Purchases of nuclear decommissioning trust securities	(1)	(3)	(10)
Sales of nuclear decommissioning trust securities	1	3	12
Other, net	—	8	(22)
Net cash used in investing activities	(1,358)	(758)	(656)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued

(In millions)

	Years Ended December 31,		
	2023	2022	2021
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 600	$ 360	$ 400
Payments on long-term debt	(260)	—	(160)
Proceeds from issuances of common stock, net of issuance costs	485	—	—
Borrowings on short-term debt	—	—	200
Payments on short-term debt	—	—	(350)
Issuance of commercial paper, net	146	—	—
Proceeds from Pelton/Round Butte financing arrangement	—	25	—
Dividends paid	(179)	(158)	(150)
Repurchase of common stock	—	(18)	(12)
Other	(14)	(12)	(9)
Net cash provided by (used in) financing activities	778	197	(81)
Change in cash and cash equivalents	(160)	113	(205)
Cash and cash equivalents, beginning of year	165	52	257
Cash and cash equivalents, end of year	$ 5	$ 165	$ 52
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 136	$ 128	$ 120
Income taxes, net	12	37	16
Non-cash investing and financing activities:			
Accrued capital additions	212	111	87
Accrued dividends payable	51	42	40

See accompanying notes to consolidated financial statements.

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.

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. For further information on PGE's jointly-owned plant, see Note 18, Jointly-Owned Plant. Intercompany balances and transactions have been eliminated.

Miscellaneous Income, Net

Miscellaneous income, net includes $19 million, $8 million, and $6 million in interest income from regulatory assets for the year ended December 31, 2023, 2022, and 2021, respectively, and $7 million realized and unrealized gains, $4 million realized and unrealized losses, and $5 million realized and unrealized gains on the non-qualified benefit plan trust assets. The remaining activity is comprised of $4 million in other miscellaneous income for the year ended December 31, 2023, $13 million in other miscellaneous income in 2022, which included an $11 million settlement gain related to the buyout of the Non-represented Retiree Medical Plan, and $2 million in other miscellaneous expense in 2021.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) 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.
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NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had none as of December 31, 2023 and $150 million as of December 31, 2022 included within Cash and cash equivalents in the consolidated balance sheets.

Accounts Receivable

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 receivable and unbilled revenues related to retail sales are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates for credit losses are based on management’s assessment of the current and forecasted probability of collection, aging of accounts receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for accounts receivable and unbilled revenues. For more information on PGE’s provision for uncollectible accounts receivable and unbilled revenues see “*Accounts Receivable, Net”* in Note 4, Balance Sheet Components.

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense 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 accounts receivable related to wholesale sales in 2023, 2022, or 2021.

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 consolidated balance sheets as assets or liabilities from price risk management activities. Changes in fair value are recognized in the consolidated statements 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 Revenues, net and Purchased power and fuel expense, respectively, upon settlement, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased power and fuel expense 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 included within Other current assets in the consolidated balance sheets 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 consolidated balance sheets 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.

Electric Utility Plant

Capitalization Policy

Electric 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 Electric utility plant on the consolidated balance sheets. 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 consolidated statements 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 expense, net, was $13 million in 2023, $7 million in 2022, and $8 million in 2021. AFUDC from equity funds, included in Other income, net, 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, 2022, and 2021. 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 depreciation. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, if applicable, and included in Regulatory liabilities.

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 both 2022 and 2021. 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 consolidated balance sheets, 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, net. 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 consolidated 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 7, 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 and fuel in the Company's consolidated statements of income, and is net of wholesale sales, which are classified as Revenues, net in the consolidated statements 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 Revenues, net in PGE's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. 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 consolidated balance sheets. 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 Electric utility plant, net on the consolidated balance sheets 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 consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements 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 consolidated statements 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 Depreciation and amortization expense in the Company's consolidated statements of income.

For additional information concerning the Company's AROs, see Note 8, 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 consolidated balance sheets. 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 7, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated 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 19, Contingencies.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) presented on the consolidated balance sheets is comprised of the difference between the obligations of the non-qualified benefit plans recognized in net income and the unfunded position.

Revenue Recognition

Revenue is 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 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 consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $56 million in 2023, $53 million in 2022, and $48 million in 2021.

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 included in Accounts receivable, net in the Company’s consolidated balance sheets, 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 revenue to be billed to customers in future periods or defers the recognition of certain 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.

Alternative Revenue Programs

Revenues related to PGE's decoupling mechanism are considered earned under alternative revenue programs, as this amount represents a contract with the regulator and not with customers. Such revenues are presented separately from revenues from contracts with customers and classified as Alternative revenue programs, net of amortization on the consolidated statements of income. The activity within this line item is comprised of current period deferral adjustments, which can either be a collection from or a refund to customers, and is net of any related amortization. When amounts related to alternative revenue programs are ultimately included in prices and customer bills, the amounts are included within Revenues, net, with an equal and offsetting amount of amortization recorded on the Alternative revenue programs, net of amortization line item.

In the 2022 General Rate Case (GRC), parties reached an agreement that has eliminated PGE's decoupling mechanism upon the effective date of new customer prices pursuant to the case, which began May 9, 2022. Pursuant to the GRC Order, the OPUC adopted the agreement such that deferrals will not occur after 2022, although amortization of then previously recorded deferrals will continue as scheduled until collected or refunded in future customer prices and deferral continued through the end of 2022 on a prorated basis. As stipulated in the 2024 GRC settlement agreement, PGE made a tariff filing, on January 26, 2024, that proposes weather-normalized decoupling, which would begin April 1, 2024 and sunset after December 31, 2025, for residential and small non-residential customers. The proposal seeks a 3% annual limit on collections or refunds and a balancing account to capture any amounts that exceed the limit, which would carry forward to subsequent years for refund or recovery.

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 14, 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.

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $177 million and $194 million as of December 31, 2023 and 2022, respectively, and will primarily be reversed using the average rate assumption method to account for the refund to customers as the temporary differences reverse.

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 consolidated balance sheets.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements 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 consolidated statements 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 consolidated financial statements and does not plan to early adopt the standard.

In December 2023, the FASB issued ASU 2023-09 *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*. ASU 2023-09 amends Topic 740 to address requests to improve transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2026. Early adoption is permitted. As the standard relates only to disclosures, PGE does not expect the adoption to have a material impact on the consolidated financial statements and does not plan to early adopt the standard.

NOTE 3: REVENUE RECOGNITION

Disaggregated Revenue

The following table presents PGE's revenue, disaggregated by customer type (in millions):

	Year Ended December 31,		
	2023	2022	2021
Retail:			
Residential	$ 1,263	$ 1,158	$ 1,118
Commercial	800	723	690
Industrial	349	289	250
Direct access customers	27	35	47
Subtotal	2,439	2,205	2,105
Alternative revenue programs, net of amortization	11	11	(29)
Other accrued revenues, net	(3)	7	2
Total retail revenues	2,447	2,223	2,078
Wholesale revenues *	418	363	255
Other operating revenues	58	61	63
Total revenues	$ 2,923	$ 2,647	$ 2,396

* Wholesale revenues include $185 million, $133 million, and $63 million related to physical electricity commodity contract derivative settlements for the years ended December 31, 2023, 2022, and 2021, respectively. Price risk management derivative activities are included within Total revenues but do not represent revenues from contracts with customers as defined by GAAP, pursuant to Topic 606. For further information, see Note 6, Risk Management.

Retail Revenues

The Company's primary revenue source is the sale of electricity to customers at regulated tariff-based prices. Retail customers are classified as residential, commercial, or industrial. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), manufactured homes, and small farms. Residential demand is sensitive to the effects of weather, with demand highest during the winter heating and summer cooling seasons. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers and are also sensitive to the effects of weather, although to a lesser extent than residential customers. Commercial customers include most businesses, small industrial companies, and public street and highway lighting accounts. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having limited impact on energy use by this customer class.

In accordance with state regulations, PGE's retail customer prices are based on the Company's cost-of-service and determined through GRC proceedings and various tariff filings with the OPUC. Additionally, the Company offers pricing options that include a daily market price option, various time-of-use options, and several renewable energy options.

Retail revenue is billed based on monthly meter readings taken throughout the month.

PGE's obligation to sell electricity to retail customers generally represents a single performance obligation representing a series of distinct services that are substantially the same and have the same pattern of transfer to the customer that is satisfied over time as customers simultaneously receive and consume the benefits provided. PGE applies the invoice method to measure its progress towards satisfactorily completing its performance obligations.

Pursuant to regulation by the OPUC, PGE is mandated to maintain several tariff schedules to collect funds from customers for programs that benefit the general public, such as conservation, low-income housing, energy efficiency, renewable energy programs, and privilege taxes. For such programs, PGE generally collects the funds and remits the amounts to third party agencies that administer the programs. In these arrangements, PGE is considered to be an agent, as PGE's performance obligation is to facilitate a transaction between customers and the administrators of these programs. Therefore, such amounts are presented on a net basis and do not appear in Revenues, net within the consolidated statements of income.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of, and secure reasonably priced power for, its retail customers, manage risk, and administer its current long-term wholesale contracts. In addition, the Company performs portfolio management and wholesale market sales services for third parties in the region. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow PGE to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro, solar, and wind conditions, and daily and seasonal retail demand.

PGE's Wholesale revenues are primarily short-term electricity sales to utilities and power marketers that consist of single performance obligations that are satisfied as energy is transferred to the counterparty. The Company may choose to net certain purchase and sale transactions in which it would simultaneously receive and deliver physical power with the same counterparty; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled and recorded in Wholesale revenues.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resale, excess fuel sales, utility pole attachment revenues, and other electric services provided to customers.

Arrangements with Multiple Performance Obligations

Certain contracts with customers, primarily wholesale, may include multiple performance obligations. For such arrangements, PGE allocates revenue to each performance obligation based on its relative standalone selling price. The Company generally determines standalone selling prices based on the prices charged to customers.

NOTE 4: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable, net includes $138 million and $131 million of unbilled revenues as of December 31, 2023 and 2022, respectively. Accounts receivable is net of an allowance for uncollectible accounts of $9 million as of December 31, 2023 and $12 million as of December 31, 2022. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2023	2022	2021
Balance as of beginning of year	$ 12	$ 26	$ 16
(Decrease)/Increase in provision *	5	(2)	35
Amounts written off, less recoveries	(8)	(12)	(25)
Balance as of end of year	$ 9	$ 12	$ 26

* Pursuant to the Company's COVID-19 deferral, certain decreases and increases in the provision for bad debt have been deferred as a net Regulatory Asset. Of the amounts recorded as decreases and increases in the provision, reductions of $10 million and increases of $29 million for the years ended December 31, 2022 and December 31, 2021, respectively, have been offset within the COVID-19 Regulatory Asset. See Note 7, Regulatory Assets and Liabilities for more information.

Other Current Assets and Accrued Expenses and Other Current Liabilities

Other current assets and Accrued expenses and other current liabilities consist of the following (in millions):

	As of December 31,	
	2023	2022
Other current assets:		
Prepaid expenses	$ 68	$ 69
Margin deposits	92	116
Assets from price risk management activities	22	313
	$ 182	$ 498
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 48	$ 234
Accrued employee compensation and benefits	74	66
Accrued dividends payable	51	42
Accrued interest payable	40	31
Accrued taxes payable	30	29
Margin deposits from wholesale counterparties	5	140
Other	107	99
	$ 355	$ 641

Electric Utility Plant, Net

Electric utility plant, net consist of the following (in millions):

	As of December 31,	
	2023	2022
Electric utility plant:		
Generation	$ 4,986	$ 4,709
Transmission	1,144	1,119
Distribution	5,252	4,813
General	1,014	973
Intangible	933	807
Total in service	13,329	12,421
Accumulated depreciation and amortization	(4,757)	(4,423)
Total in service, net	8,572	7,998
Construction work-in-progress *	974	467
Electric utility plant, net	$ 9,546	$ 8,465

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

NOTE 5: 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 consolidated balance sheets, 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:					
Cash equivalents	$ —	$ —	$ —	$ —	$ —
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 securities—domestic	—	—	—	—	—
Debt securities—domestic 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 regulatory assets or 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 6, Risk Management.

	December 31, 2022				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Cash equivalents	$ 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 securities—domestic	3	—	—	—	3
Debt securities—domestic 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 regulatory assets or 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 6, Risk Management.

Cash equivalents 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. Cash equivalents 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 in PGE's consolidated balance sheets 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 consolidated balance sheets, 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 6, 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 consolidated balance sheets. 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 $3,985 million, net of $14 million of unamortized debt expense, 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 $3,646 million, net of $13 million of unamortized debt expense, with an estimated aggregate fair value of $2,984 million.

For fair value information concerning the Company's pension plan assets, see Note 11, Employee Benefits.

NOTE 6: 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 consolidated balance sheets, may include forward, future, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the consolidated statements 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[1]	22	313
Noncurrent assets:		
Commodity contracts:		
Electricity	9	44
Natural gas	2	30
Total noncurrent derivative assets[1]	11	74
Total derivative assets[2]	$ 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[2]	$ 239	$ 193

(1) Total current derivative assets is included in Other current assets, and Total noncurrent derivative assets is included in Other noncurrent assets on the consolidated balance sheets.
(2) As of December 31, 2023 and 2022, no commodity derivative assets or liabilities were designated as hedging instruments.

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 consolidated 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 Price risk management 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 Price risk management 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 and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,					
	2023		2022		2021	
Commodity contracts:						
Electricity	$	(130)	$	(187)	$	(38)
Natural Gas		357		(388)		(177)
Foreign currency contracts		(1)		1		—

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net losses of $403 million, net gains of $188 million, and net gains of $119 million for the years ended December 31, 2023, 2022, and 2021, 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 Margin deposits included in Other current assets on the Company's consolidated 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 consolidated balance sheets.

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 5, Fair Value of Financial Instruments.

NOTE 7: 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):

	As of December 31,				
		2023			2022
	Remaining Amortization Period	Earning a Return (1)	Not Earning a Return	Total	Total
Regulatory assets:					
Price risk management	(2)	$ —	$ 206	$ 206	$ 1
Pension and other postretirement plans	(3)	—	104	104	95
Debt issuance costs	2049	—	20	20	21
Trojan decommissioning activities	2059	—	139	139	133
February 2021 ice storm and damage	(4)	67	—	67	74
Power cost adjustment mechanism	(5)	16	—	16	28
2020 Labor Day wildfire	(4)	28	—	28	31
COVID-19	(6)	14	—	14	22
Wildfire mitigation	(7)	29	—	29	28
Other	Various	58	32	90	94
Total regulatory assets		$ 212	$ 501	$ 713	$ 527
Regulatory liabilities:					
Asset retirement removal costs	(8)	$ 1,173	$ —	$ 1,173	$ 1,136
Deferred income taxes	(9)	177	—	177	194
Price risk management	(2)	—	—	—	195
Other	Various	82	14	96	98
Total regulatory liabilities		$ 1,432	$ 14	$ 1,446	$ 1,623

(1) Earning a return includes either interest on the regulatory asset or liability, or inclusion of the regulatory asset or liability as an increase or decrease to rate base at the allowed rate of return.
(2) 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.
(3) Recovery expected over the average service life of employees.
(4) Amortization will occur over a 7-year period starting January 1, 2023.
(5) Amortization will occur over a 2-year period starting January 1, 2023.
(6) Amortization will occur over a 2-year period starting April 1, 2023.
(7) 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.
(8) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(9) 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 6, 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 11, 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:

- <u>Base Rates</u> - The outcome of PGE's 2022 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.
- <u>Previously Deferred</u> - 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.

Asset retirement removal costs represents the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

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 12, 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 of the ARO; and ii) the amount recovered in customer prices.

NOTE 8: 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
Less: current portion *	14	32
Noncurrent asset retirement obligations	$ 272	$ 257

* Current portion of AROs are classified within Accrued expenses and other current liabilities in the consolidated balance sheets.

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 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 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 Depreciation and amortization on the consolidated statements 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 Depreciation and amortization expense.

PGE maintains a separate Nuclear decommissioning trust in the consolidated 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 asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

NOTE 9: 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 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.

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 Short-term debt in the consolidated balance sheets.

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 consolidated balance sheets.

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	2021
Average daily amount of short-term debt outstanding	$ 63	$ 2	$ 139
Weighted daily average interest rate *	5.5 %	3.4 %	0.9 %
Maximum amount outstanding during the year	$ 225	$ 135	$ 230

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

NOTE 10: 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 Electric utility plant, net on the consolidated balance sheets as if it were the legal owner and will continue to recognize depreciation expense over the estimated useful life. The monthly PPA payments are split between interest expense 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 11: 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 consolidated 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 5, 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 in PGE's consolidated balance sheets 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 *	16	63	79	16	67	83

* For the NQBP, excludes the current portion of $2 million in 2023 and $2 million in 2022, which are classified in Accrued expenses and other current liabilities in the consolidated balance sheets.

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 securities—Domestic	$ 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 securities—Domestic	—	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 securities—Domestic	$ 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 securities—Domestic 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 5, 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 consolidated 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 Regulatory assets or liabilities 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	2021	2023	2022	2021	2023	2022	2021
Service cost	$ 10	$ 17	$ 19	$ 1	$ 1	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	37	28	27	2	2	2	1	1	1
Expected return on plan assets	(43)	(46)	(45)	(1)	(2)	(2)	—	—	—
Amortization of prior service credit	(1)	(2)	—	—	—	(1)	—	—	—
Amortization of net actuarial loss	—	15	22	(1)	—	—	1	1	1
Settlement gain	—	—	—	(1)	(11)	—	—	—	—
Net periodic benefit cost	$ 3	$ 12	$ 23	$ —	$ (10)	$ 1	$ 2	$ 2	$ 2

The portion of non-service costs attributable to expense related to the pension and other postretirement benefit plans, is classified as Miscellaneous income (expense), net within Other income, net on the Company's consolidated statements of income. A portion of current period non-service costs attributable capital projects is recorded as a regulatory asset and amortized to Miscellaneous income (expense), net over time.

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 12: INCOME TAXES

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

	Years Ended December 31,		
	2023	2022	2021
Current:			
Federal	$ 11	$ 9	$ 4
State and local	26	24	14
	37	33	18
Deferred:			
Federal	4	(1)	—
State and local	4	7	5
	8	6	5
Income tax expense	$ 45	$ 39	$ 23

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	2021
Federal statutory tax rate	21.0 %	21.0 %	21.0 %
Federal tax credits (1)	(9.5)	(12.8)	(13.0)
State and local taxes, net of federal tax benefit	8.6	8.8	8.9
Flow through depreciation and cost basis differences	(0.4)	0.8	(0.2)
Local tax flow-through adjustment (2)	—	—	(3.2)
Reversal of excess deferred income tax (3)	(3.9)	(4.5)	(4.8)
Other	0.6	1.0	(0.1)
Effective tax rate	16.4 %	14.3 %	8.6 %

(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) In 2021, PGE recognized a regulatory asset to defer previously recorded deferred income tax expenses in the amount of $9 million with a corresponding credit to Income tax expense reflected in the consolidated statements of income for the year ended December 31, 2021.

(3) The majority of excess deferred income taxes related to remeasurement under the TCJA is subject to 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
Regulatory liabilities	21	75
Tax credits	73	102
Price risk management	57	—
Total deferred income tax assets	250	276
Deferred income tax liabilities:		
Depreciation and amortization	578	547
Price risk management	—	54
Regulatory assets	146	101
Other	14	13
Total deferred income tax liabilities	738	715
Deferred income tax liability, net	$ 488	$ 439

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 consolidated 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 consolidated financial statements. The Internal Revenue Service (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 consolidated financial statements.

NOTE 13: 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.

Prior to settlement, the potentially issuable shares pursuant to the EFSA were reflected in PGE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE's common stock used in calculating diluted earnings per share for a reporting period would be increased by the number of shares, if any, that would be issued upon physical settlement of the EFSA less the number of shares that could be purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period). Share dilution occurs when the average market price of PGE's stock during the reporting period is higher than the average forward sale price during the reporting period. For additional information concerning the Company's diluted earnings per share, see Note 15, Earnings Per Share.

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 14: 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, 2020	478,396	$ 48.00
Granted	318,844	43.01
Forfeited	(9,754)	48.35
Vested	(212,676)	40.33
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 shareholders 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, $5 million for 2022, and $3 million for 2021.

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 portfolio—and relative total shareholder 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	2021
Risk-free interest rate	4.2 %	1.7 %	0.2 %
Expected term (in years)	2.9	2.9	2.9
Volatility	21.8 % - 31.5 %	26.4 % - 37.9 %	26.1 % - 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, $6 million for 2022, and $7 million for 2021.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $17 million for the year ended December 31, 2023, $15 million for 2022, and $14 million in 2021. Such amounts differ from those reported in the consolidated statements of shareholders' equity 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 other expenses in the consolidated statements of income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to shareholders' equity of $4 million in 2023 and in 2022, and $1 million in 2021.

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 15: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; ii) contingently issuable time-based and performance-based restricted stock units, along with associated DERs; and iii) shares issuable pursuant to the EFSA and at the market offering program. See Note 13, Equity-based Plans, for additional information on the EFSA and at the market offering program and the resulting impact on earnings per share. Unvested performance-based restricted stock units and associated DERs are included in dilutive potential common shares only after the performance criteria have been met. Anti-dilutive stock awards are excluded from the calculation of diluted earnings per common share.

Net income attributable to PGE common shareholders is the same for both the basic and diluted earnings per share computations. The reconciliations of the denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Years Ended December 31,		
	2023	2022	2021
Weighted average common shares outstanding—basic	97,760	89,290	89,481
Dilutive potential common shares	192	353	146
Weighted average common shares outstanding—diluted	97,952	89,643	89,627

NOTE 16: 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 and fuel:							
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 Consolidated Statements 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 consolidated balance sheets with respect to these indemnities.

NOTE 17: 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 consolidated balance sheets 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.

Operating leases reflect lease expense on a straight-line basis, while finance leases result in the separate presentation of interest expense on the lease liability and amortization expense of the ROU asset. 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.

PGE does not record leases with a term of 12-months or less in the consolidated balance sheets. 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 consolidated balance sheets is presented below (in millions):

	Balance Sheet Classification	As of December 31, 2023	2022
Operating Leases:			
Operating lease right-of-use assets	Other noncurrent assets	$ 18	$ 22
Current liabilities	Accrued expenses and other current liabilities	$ 3	$ 4
Noncurrent liabilities	Other noncurrent liabilities	16	18
Total operating lease liabilities *		$ 19	$ 22
Finance Leases:			
Finance lease right-of-use assets	Electric utility plant, net	$ 291	$ 305
Current liabilities	Current portion of finance lease obligations	$ 20	$ 20
Noncurrent liabilities	Finance lease obligations, net of current portion	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	2021
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 4	$ 4	$ 8
Operating cash flows from finance leases	15	15	11
Financing cash flows from finance leases	6	7	6
Right-of-use assets obtained in leasing arrangements:			
Operating leases	$ —	$ —	$ (12)
Finance leases	—	29	153

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 18: 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 asset retirement removal costs.

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 consolidated statements 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 19: 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—I*n 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 arbitration has been stayed through April 1, 2024, by agreement of the parties. 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 20: 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 currently estimates the incremental incurred and future costs to repair damage to PGE's transmission and distribution systems and restore power to customers could range from $50 million to $60 million, with $35 million to $45 million of that range estimated to represent operating expenses associated with transmission and distribution. 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 costs as regulatory assets.

Due to the storm and corresponding impact on power markets, PGE has incurred a substantial amount of incremental net variable power costs 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. Estimates of the total cost for the RCE are still under development, however the Company believes total costs could be in the range of $85 million to $100 million. Full impacts cannot be determined until all settlements and invoices are received for the period to which the RCE applies. PGE expects to defer a significant majority of these costs through its various OPUC approved mechanisms over net variable power costs.

PGE believes it has adequate liquidity to cover the event.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective.

(b) Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2023, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2023, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2023.

(c) Changes in Internal Control over Financial Reporting

In the fourth quarter of 2023, PGE implemented new financial systems, including an enterprise resource planning system and an enterprise performance management system. The systems replaced existing systems and are primarily used for financial reporting processes and certain operational activities. In connection with the implementations, the Company modified the design and implementation of certain internal control processes and procedures. Management will continue to evaluate and monitor the internal controls over the Company's financial reporting process, including monitoring the operating effectiveness of related key controls.

Other than with respect to the implementations noted above, there were no other changes to PGE's internal control over financial reporting during the fourth quarter of 2023 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

Rule 10b5-1 Trading Arrangements

During the year ended December 31, 2023, the following directors or officers (as defined in Rule 16a-1(f) of the Exchange Act) adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(c) of Regulation S-K):

Name (Title)	Action Taken (Date of Action)	Type of Trading Arrangement	Duration of Trading Arrangement	Aggregate Number of Securities to be Purchased or Sold
Larry Bekkedahl (Senior Vice President, Advanced Energy Delivery)	Adoption (November 10, 2023)	Rule 10b5-1 trading arrangement	Until February 14, 2024, or such earlier date upon which all transactions are completed or expire without execution	Up to 3,384 shares of common stock
Benjamin Felton (Executive Vice President Chief Operating Officer)	Adoption (December 6, 2023)	Rule 10b5-1 trading arrangement	Until December 5, 2024, or such earlier date upon which all transactions are completed or expire without execution	Up to 1,927 shares of common stock

ITEM 9C. DISCLOSURES REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Certain information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Corporate Governance" and "Item 1: Election of Directors" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the United States Securities and Exchange Commission (SEC) in connection with the Annual Meeting of Shareholders scheduled to be held on April 19, 2024. Information regarding executive officers of Portland General Electric Company may be found in Part I, Item 1. Business of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Item 1: Election of Directors—Director Compensation," "Item 1: Election of Directors—Board Committees—Compensation, Culture and Talent Committee—Compensation, Culture and Talent Committee Interlocks," "Compensation, Culture and Talent Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 19, 2024.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 19, 2024.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 19, 2024.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 19, 2024.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1).
3.2*	Twelfth Amended and Restated Bylaws of Portland General Electric Company (Form 10-Q filed October 27, 2023, Exhibit 3.2).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (Form 8-K filed August 3, 2017, Exhibit 4.1).
4.4*	Seventy-fifth Supplemental Indenture, dated April 1, 2019, between the Company and Wells Fargo Bank, National Association, as trustee (Form 8-K filed April 15, 2019, Exhibit 4.1).
4.5*	Description of Securities (Form 10-K filed February 15, 2019, Exhibit 4.6).
(10)	**Material Contracts**
10.1*	First Amendment to Credit Agreement, dated as of September 9, 2022, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders. (8-K filed September 9, 2022, Exhibit 10.1).

Exhibit Number	Description
10.2*	Second Amendment to Credit Agreement, dated as of August 18, 2023, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (8-K filed August 22, 2023, Exhibit 10.1).
10.3*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.4*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.5*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.6*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.7*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.8*	Form of Directors' Restricted Stock Unit Agreement (Form 10-K filed February 15, 2019, Exhibit 10.18).+
10.9*	Portland General Electric Company Amended and Restated Severance Pay Plan for Executive Employees (the "Amended Plan"), effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.1).+
10.10*	Portland General Electric Company Annual Cash Incentive Plan as amended and restated effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.2).+
10.13*	Portland General Electric Company Stock Incentive Plan as amended and restated effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.3).+
10.14*	Form of Officers' and Key Employees' Performance Stock Unit Agreement. (Form 10-K filed February 17, 2022, Exhibit 10.15).+
10.15*	Form of Officers' and Key Employees' Restricted Stock Unit Agreement. (Form 10-K filed February 17, 2022, Exhibit 10.16).+
10.16*	Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 10-Q filed October 27, 2023, Exhibit 10.1).+
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
97.1	Portland General Electric Company Amended and Restated Incentive Compensation Clawback and Cancellation Policy.
(101)	**Interactive Data File**
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.

Exhibit Number	Description
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover page information from Portland General Electric Company's Annual Report on Form 10-K filed February 20, 2024, formatted in iXBRL (Inline Extensible Business Reporting Language).

* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 20, 2024.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ MARIA M. POPE

Maria M. Pope
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 20, 2024.

Signature	Title
/s/ MARIA M. POPE **Maria M. Pope**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JOSEPH R. TRPIK **Joseph R. Trpik**	*Senior Vice President, Finance and Chief Financial Officer* (principal financial and accounting officer)
/s/ DAWN L. FARRELL **Dawn L. Farrell**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ MARIE OH HUBER **Marie Oh Huber**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*Director*
/s/ MICHAEL A. LEWIS **Michael A. Lewis**	*Director*
/s/ MICHAEL H. MILLEGAN **Michael H. Millegan**	*Director*
/s/ JOHN O'LEARY **John O'Leary**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ PATRICIA S. PINEDA **Patricia S. Pineda**	*Director*
/s/ JAMES P. TORGERSON **James P. Torgerson**	*Director*

Corporate Information

BOARD OF DIRECTORS

Maria Pope
President and Chief Executive Officer, Portland General Electric

James P. Torgerson
Board Chair,
Retired Chief Executive Officer,
AVANGRID Inc.

Dawn Farrell
President and Chief Executive Officer, Trans Mountain Corporation

Mark Ganz
Retired President and
Chief Executive Officer, Cambia Health Solutions, Inc.

Marie Oh Huber
Senior Vice President,
Chief Legal Officer, General Counsel and Secretary, eBay Inc.

Kathryn Jackson, PhD
Senior Advisor, Energy Impact Partners

Michael Lewis
Former Interim President, Pacific Gas and Electric Company

Michael Millegan
Founder and Chief Executive Officer,
Millegan Advisory Group 3 LLC

John O'Leary
President and Chief Executive Officer, Daimler Trucks North America

M. Lee Pelton
President and Chief Executive Officer, The Boston Foundation

Patricia Salas Pineda
Retired Group Vice President,
Toyota Motor North America, Inc.

CORPORATE OFFICERS

Maria Pope
President and Chief Executive Officer

Benjamin Felton
Executive Vice President, Chief Operating Officer

Larry Bekkedahl
Senior Vice President, Strategy and Advanced Energy Delivery

Angelica Espinosa
Senior Vice President, Chief Legal and Compliance Officer

Joseph Trpik
Senior Vice President, Finance and Chief Financial Officer

John Kochavatr
Vice President,
Customer & Digital Solutions
and Chief Information Officer

Anne Mersereau
Vice President, Human Resources,
Diversity, Equity and Inclusion

Brett Sims
Vice President, Strategy,
Energy Supply

INVESTOR INFORMATION

Corporate Headquarters
Portland General Electric Company
121 SW Salmon St.
Portland, OR 97204
503-464-8000
investors.portlandgeneral.com

Transfer Agent
Equiniti Trust Company, LLC
48 Wall Street, Floor 23
New York, NY 10005
800-468-9716

Independent Auditors
Deloitte & Touche LLP
U.S. Bancorp Tower
111 SW 5th Ave.
Suite 3900
Portland, OR 97204
503-222-1341

Form 10-K
A copy of the Company's 2023 Annual Report on Form 10-K will be furnished, without charge, upon written request made to:

Nick White
Manager of Investor Relations
121 SW Salmon St.
1WTC0504
Portland, OR 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503-464-8073 or by downloading a copy at no charge from investors.portlandgeneral.com.

Market Information
Portland General Electric Company stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online, visit investors.portlandgeneral.com.

PGE