

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)

Portland General Electric Company

Year/Period of Report
End of: 2025/ Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

- a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.
- b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
- c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426
- d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

<u>Schedules</u>	<u>Pages</u>
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 filed..."

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: 2025/ 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)

04/13/2026

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)

04/13/2026

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: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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LIST OF SCHEDULES (Electric Utility)

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	none
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	not applicable
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	none
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	none
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228	
24	Extraordinary Property Losses	230a	none
25	Unrecovered Plant and Regulatory Study Costs	230b	

LIST OF SCHEDULES (Electric Utility)

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
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	
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	

LIST OF SCHEDULES (Electric Utility)

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
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	not applicable
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	
63.1	Renewable Generating Plant Statistics	404	
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	
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: <input type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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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.

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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.

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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 through the purchase and sale of electricity, natural gas, and environmental credits in an effort to obtain reasonably-priced power to serve its retail customers, manage risk, and administer its long-term wholesale contracts.

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

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CORPORATIONS CONTROLLED BY RESPONDENT

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 owns 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 provides property management for the Respondent and holds the World Trade Center Franchise	100%	
3	Salmon Springs Hospitality Group, Inc.	Company hosts Corporate and social gatherings and events.	100%	Dissolved 5/23/25
4	121 SW Salmon Street LLC	Established to own, lease and manage the World Trade Center in Portland Oregon		
5	Portland Renewable Resource Company LLC	Established to conduct any lawful purpose		

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OFFICERS

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 1,205,111		
2	Senior Vice President, Advanced Energy Delivery	Larry N. Bekkedahl	402,234		
3	Vice President, Digital Solutions and Chief Information Officer	John Kochavatr	533,284		
4	Vice President, Human Resources, Diversity, Equity and Inclusion	Anne E. Mersereau	18,681		2025-01-11
5	Senior Vice President, Chief Legal and Compliance Officer	Angelica Espinosa	596,522		
6	Executive Vice President, Chief Operating Officer	Benjamin Felton	735,502		
7	Senior Vice President and Chief Financial Officer	Joseph Trpik	690,788		
8	Vice President Chief Commercial and Customer Officer	John McFarland	517,959		
9	Vice President Utility Operations	Debbie Powell	475,125		
10	Vice President Policy and Resource Planning	Kristen Sheeran	380,946		
11	Vice President Power Markets and Grid Operations	Martin Wyspianski	340,659	2025-04-28	
12	Chief Human Resources Officer & Vice President of People & Culture	Juan Gallegos	327,329	2025-04-28	

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FOOTNOTE DATA

(a) Concept: OfficerSalary

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

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DIRECTORS

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	Kathryn J. Jackson	Portland, Oregon		
2	Maria M. Pope President and Chief Executive Officer	Portland, Oregon		
3	Marie Oh Huber	Portland, Oregon		
4	Michael H. Millegan	Portland, Oregon		
5	Michael L. Lewis	Portland, Oregon		
6	James P. Torgerson Chair of the Board	Portland, Oregon		
7	^(a) Dawn L. Farrell	Portland, Oregon		
8	Patricia S. Pineda	Portland, Oregon		
9	John O'Leary	Portland, Oregon		
10	^(b) Renee James	Portland, Oregon		

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FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

October 1, 2025, Dawn Farrell resigned from the Board.

(b) Concept: NameAndTitleOfDirector

Join date: June 11, 2025

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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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 12, 2026, issued an order in Docket No. ES26-16-000 that authorizes the Company to issue up to \$900 million of short-term debt through February 6, 2028. 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.

On September 10, 2025, PGE entered into an amendment of its existing revolving credit facility that extended the scheduled expiration into September 2030. As of December 31, 2025, PGE had a \$750 million revolving credit facility that provides the Company the ability to expand 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% of total capitalization. As of December 31 2025, PGE was in compliance with this covenant with a 53.0% debt to total capital ratio and had no outstanding balance and there were no letters of credit issued under the revolving credit facility.

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 in order to allow for coverage of any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2025, PGE had no commercial paper outstanding.

Under the revolving credit facility, as of December 31, 2025, 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.

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, letters of credit for a total of \$192 million were outstanding as of December 31, 2025. Outstanding letters of credit are not reflected on the Company's Comparative Balance Sheet.

On March 25, 2025, PGE entered into a Bond Purchase Agreement related to the sale of \$310 million in First Mortgage Bonds (FMBs). The Bonds were issued and funded in full on March 25, 2025 and consist of:

- a series, due in 2035, in the amount of \$60 million that will bear interest from its issuance date at an annual rate of 5.36%;
- a series, due in 2045, in the amount of \$50 million that will bear interest from its issuance date at an annual rate of 5.72%; and;
- a series, due in 2055, in the amount of \$200 million that will bear interest from its issuance date at an annual rate of 5.84%.

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 November 14, 2024, the Company drew a \$220 million loan under a 366-day term loan agreement. On December 31, 2024, PGE repaid \$50 million of the term loan, on March 31, 2025, repaid another \$102 million, and on October 27, 2025, repaid the remaining balance of \$68 million, repaying the loan in full.

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. As of December 31, 2025, 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:

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in the state of Montana and operated by one of the co-owners, Talen Montana, LLC. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. In 2021, an arbitration process was initiated by co-owner, NorthWestern Corporation, against all other co-owners of Colstrip to address such business disagreements and 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 parties have agreed to stay the arbitration proceedings indefinitely. PGE cannot predict the ultimate outcome of this matter.

Wrongful Death Claims

In September 2025, PGE received a complaint filed in Multnomah County Circuit Court on behalf of the estates of three members of the public and their relatives, with regard to three fatalities that occurred during the January 2024 storm and severe winter weather event. The lawsuit seeks a total of \$375 million related to their deaths and surviving family members' claims. Business entities that own and operate an apartment complex, along with a nearby property owner, are also named as defendants. At this time, as the case is in its early stages, PGE is unable to estimate a range of any reasonably possible loss. The Company denies liability and plans to defend its case.

10. None

11. (Reserved)

12. None

13. Changes in Officers:

On January 11, 2025, Anne Mersereau, Vice President of Human Resources, Diversity, Equity & Inclusion, retired.

On April 28, 2025, Juan Gallegos joined the Company as Chief Human Resources Officer and Vice President of People & Culture.

On April 28, 2025, Martin Wyspianski joined the Company as Vice President of Power Markets and Grid Operation.

On June 2, 2025, Larry Bekkedahl, Senior Vice President of Strategy and Advanced Energy Delivery transitioned to part time.

Changes in Directors:

The number of Directors on the Board decreased from nine to eight on October 1, 2025 when Dawn Farrell resigned from the Board.

14. None

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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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	16,218,702,929	15,111,925,280
3	Construction Work in Progress (107)	200	414,862,438	569,951,129
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,633,565,367	15,681,876,409
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	6,556,171,085	6,196,192,797
6	Net Utility Plant (Enter Total of line 4 less 5)		10,077,394,282	9,485,683,612
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)		10,077,394,282	9,485,683,612
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		2,892,138	2,892,161
19	(Less) Accum. Prov. for Depr. and Amort. (122)		580,889	549,606
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224	89,052,874	86,245,684
23	Noncurrent Portion of Allowances and Environmental Credits	228	0	0
24	Other Investments (124)		18,809,411	13,246,789
25	Sinking Funds (125)		0	0

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)
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		84,797,541	69,963,786
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,449,111	2,161,907
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		196,420,186	173,960,721
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,030,226	460,719
36	Special Deposits (132-134)		123,237,654	125,094,853
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		59,000,000	12,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		227,154,932	231,923,765
41	Other Accounts Receivable (143)		65,100,969	58,056,268
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		12,540,157	11,815,522
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		17,021	1,786,663
45	Fuel Stock (151)	227	20,520,498	21,338,923
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	94,244,273	87,914,386
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 and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228	4,450,707	513,783

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)
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228	0	0
54	Stores Expense Undistributed (163)	227	4,756,089	4,343,197
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)		99,185,007	98,995,958
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)		180,135,074	177,284,816
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		33,040,014	34,395,859
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,449,111	2,161,907
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)		913,883,196	840,131,761
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		16,688,208	14,608,223
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	161,162,526	160,790,054
72	Other Regulatory Assets (182.3)	232	669,563,221	724,330,912
73	Prelim. Survey and Investigation Charges (Electric) (183)		8,535,817	10,522,530
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)		42,580	(9)
77	Temporary Facilities (185)		1,124	36,671
78	Miscellaneous Deferred Debits (186)	233	11,705,880	9,730,684

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)
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)		14,123,482	14,986,918
82	Accumulated Deferred Income Taxes (190)	234	623,480,258	590,385,635
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,505,303,096	1,525,391,618
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,693,000,760	12,025,167,712

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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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	2,406,878,394	2,122,277,163
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	44,095,927	23,113,532
11	Retained Earnings (215, 215.1, 216)	118	1,750,034,536	1,676,875,055
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	11,523,213	8,706,023
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)	(3,792,791)	(3,855,949)
16	Total Proprietary Capital (lines 2 through 15)		4,139,337,143	3,799,678,478
17	LONG-TERM DEBT			
18	Bonds (221)	256	4,678,800,000	4,368,800,000
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	170,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		256,678	281,074
24	Total Long-Term Debt (lines 18 through 23)		4,678,543,322	4,538,518,926
25	OTHER NONCURRENT LIABILITIES			

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)
26	Obligations Under Capital Leases - Noncurrent (227)		565,806,493	588,409,041
27	Accumulated Provision for Property Insurance (228.1)		800,000	300,000
28	Accumulated Provision for Injuries and Damages (228.2)		5,672,497	5,896,183
29	Accumulated Provision for Pensions and Benefits (228.3)		188,812,455	225,147,883
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	2,705,614
32	Long-Term Portion of Derivative Instrument Liabilities		55,663,470	71,721,254
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		311,621,399	309,492,546
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,128,376,314	1,203,672,521
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		463,591,071	478,425,863
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		10,252,081	12,155,943
41	Customer Deposits (235)		59,069,435	26,675,753
42	Taxes Accrued (236)	262	16,438,597	19,197,791
43	Interest Accrued (237)		53,263,455	48,514,317
44	Dividends Declared (238)		62,844,522	57,371,089
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		28,512,528	21,945,265
48	Miscellaneous Current and Accrued Liabilities (242)		22,863,904	46,682,459
49	Obligations Under Capital Leases-Current (243)		58,826,910	59,172,193
50	Derivative Instrument Liabilities (244)		213,937,754	219,038,315

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)
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		55,663,470	71,721,254
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)		933,936,787	917,457,734
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		825,424	605,021
57	Accumulated Deferred Investment Tax Credits (255)	266	194,060,311	60,671,318
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	39,544,017	27,080,559
60	Other Regulatory Liabilities (254)	278	352,120,895	320,924,678
61	Unamortized Gain on Reacquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,027,088,246	944,427,755
64	Accum. Deferred Income Taxes-Other (283)		199,168,301	212,130,722
65	Total Deferred Credits (lines 56 through 64)		1,812,807,194	1,565,840,053
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,693,000,760	12,025,167,712

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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STATEMENT OF INCOME

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)
1	UTILITY OPERATING INCOME							
2	Operating Revenues (400)	300	3,548,184,245	3,460,714,742			3,548,184,245	3,460,714,742
3	Operating Expenses							
4	Operation Expenses (401)	320	1,961,359,620	2,003,804,192			1,961,359,620	2,003,804,192
5	Maintenance Expenses (402)	320	326,003,423	274,450,195			326,003,423	274,450,195
6	Depreciation Expense (403)	336	525,171,285	392,816,166			525,171,285	392,816,166
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	1,431,028	13,420,449			1,431,028	13,420,449
8	Amort. & Depl. of Utility Plant (404-405)	336	3,842,149	79,219,629			3,842,149	79,219,629
9	Amort. of Utility Plant Acq. Adj. (406)	336	0	0			0	0
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,900,046	1,899,953			1,900,046	1,899,953
11	Amort. of Conversion Expenses (407.2)		0	0			0	0
12	Regulatory Debits (407.3)		30,353,150	21,600,074			30,353,150	21,600,074
13	(Less) Regulatory Credits (407.4)		11,724,528	16,653,804			11,724,528	16,653,804
14	Taxes Other Than Income Taxes (408.1)	262	187,937,578	173,230,151			187,937,578	173,230,151
15	Income Taxes - Federal (409.1)	262	6,460,018	5,845,379			6,460,018	5,845,379

STATEMENT OF INCOME

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)
16	Income Taxes - Other (409.1)	262	15,751,884	13,653,558			15,751,884	13,653,558
17	Provision for Deferred Income Taxes (410.1)	234, 272	544,565,394	830,068,797			544,565,394	830,068,797
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	647,188,660	872,487,715			647,188,660	872,487,715
19	Investment Tax Credit Adj. - Net (411.4)	266	133,710,395	60,295,123			133,710,395	60,295,123
20	(Less) Gains from Disp. of Utility Plant (411.6)		0	0			0	0
21	Losses from Disp. of Utility Plant (411.7)		0	0			0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0			0	0
23	Losses from Disposition of Allowances (411.9)		0	0			0	0
24	Accretion Expense (411.10)		3,139,198	3,163,181			3,139,198	3,163,181
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)		33,331,250	0			33,331,250	0
24.2	Losses from Disposition of Environmental Credits (411.12)		0	0			0	0
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		3,049,380,730	2,984,325,328			3,049,380,730	2,984,325,328
27	Net Util Oper Inc (Enter Tot line 2 less 25)		498,803,515	476,389,414			498,803,515	476,389,414
28	Other Income and Deductions							
29	Other Income							

STATEMENT OF INCOME

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)
30	Nonutility Operating Income							
31	Revenues From Merchandising, Jobbing and Contract Work (415)		60,990	0				
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		(28,678)	0				
33	Revenues From Nonutility Operations (417)		3,560,877	3,769,578				
34	(Less) Expenses of Nonutility Operations (417.1)		4,993,741	7,021,690				
35	Nonoperating Rental Income (418)		(324,157)	308,684				
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,862,508	1,278,305				
37	Interest and Dividend Income (419)		3,725,004	5,954,821				
38	Allowance for Other Funds Used During Construction (419.1)		17,686,684	23,190,377				
39	Miscellaneous Nonoperating Income (421)		17,734,070	17,884,638				
40	Gain on Disposition of Property (421.1)		2,725	0				
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		39,343,638	45,364,713				
42	Other Income Deductions							
43	Loss on Disposition of Property (421.2)							
44	Miscellaneous Amortization (425)							
45	Donations (426.1)		2,092,812	2,448,733				

STATEMENT OF INCOME

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)
46	Life Insurance (426.2)		(2,996,000)	(1,865,398)				
47	Penalties (426.3)		4,207	217,991				
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,329,176	1,683,614				
49	Other Deductions (426.5)		16,406,881	11,437,125				
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		17,837,076	13,922,065				
51	Taxes Applic. to Other Income and Deductions							
52	Taxes Other Than Income Taxes (408.2)	262	294,082	414,051				
53	Income Taxes-Federal (409.2)	262	(4,260,284)	(4,248,414)				
54	Income Taxes-Other (409.2)	262	(1,787,239)	(1,813,370)				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	13,664,808	8,217,792				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	8,190,868	2,702,006				
57	Investment Tax Credit Adj.-Net (411.5)							
58	(Less) Investment Tax Credits (420)		8,957	0				
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(288,458)	(131,947)				
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		21,795,020	31,574,595				

STATEMENT OF INCOME

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)
61	Interest Charges							
62	Interest on Long-Term Debt (427)		212,570,060	195,186,585				
63	Amort. of Debt Disc. and Expense (428)		1,428,894	1,539,130				
64	Amortization of Loss on Reaquired Debt (428.1)		1,115,979	1,104,802				
65	(Less) Amort. of Premium on Debt-Credit (429)		0	0				
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		0	0				
67	Interest on Debt to Assoc. Companies (430)		0	0				
68	Other Interest Expense (431)		9,153,903	9,172,712				
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		11,263,956	15,344,389				
70	Net Interest Charges (Total of lines 62 thru 69)		213,004,880	191,658,840				
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		307,593,655	316,305,169				
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				

STATEMENT OF INCOME

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)
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)		307,593,655	316,305,169				

STATEMENT OF INCOME

Line No.	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				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
24.1				
24.2				
25	0	0	0	0
27	0	0	0	0
28				
29				

STATEMENT OF INCOME

Line No.	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)
30				
31				
32				
33				
34				
35				
36				
37				
38				
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41				
42				
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57				
58				
59				

STATEMENT OF INCOME

Line No.	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)
60				
61				
62				
63				
64				
65				
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72				
73				
74				
75				
76				
77				
78				

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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STATEMENT OF RETAINED EARNINGS

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Date Balance (c)	Year to Previous Quarter/Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,673,022,262	1,565,144,187
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				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1				
10.2				
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
15	TOTAL Debits to Retained Earnings (Acct. 439)			

STATEMENT OF RETAINED EARNINGS

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)
16	Balance Transferred from Income (Account 433 less Account 418.1)		305,731,147	315,026,864
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)		(231,616,984)	(207,148,789)
30.2				
30.3				
30.4				
30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(231,616,984)	(207,148,789)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		(954,682)	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,746,181,743	1,673,022,262
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				
39.2				

STATEMENT OF RETAINED EARNINGS

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Date Balance (c)	Year to Previous Quarter/Year to Date Balance (d)
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)		1,750,034,536	1,676,875,055
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		8,706,023	7,427,718
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,862,508	1,278,305
51	(Less) Dividends Received (Debit)		(954,682)	
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				
53	Balance-End of Year (Total lines 49 thru 52)		11,523,213	8,706,023

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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STATEMENT OF CASH FLOWS

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)	307,593,655	316,305,169
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	530,444,462	485,456,244
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Discount	2,544,873	2,643,932
5.2	Amortization of Unrecovered Plant	1,900,046	1,899,953
5.3	Net Price Risk Management Activities	(3,744,716)	(21,494,200)
8	Deferred Income Taxes (Net)	36,561,069	(36,903,130)
9	Investment Tax Credit Adjustment (Net)	8,957	0
10	Net (Increase) Decrease in Receivables	176,134,712	70,145,639
11	Net (Increase) Decrease in Inventory	(9,861,278)	(1,210,430)
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory	0	0
13	Net Increase (Decrease) in Payables and Accrued Expenses	45,018,652	53,577,232
14	Net (Increase) Decrease in Other Regulatory Assets	48,331,802	(98,593,793)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(35,829,819)	9,204,285
16	(Less) Allowance for Other Funds Used During Construction	17,686,684	23,190,377
17	(Less) Undistributed Earnings from Subsidiary Companies	1,862,508	1,278,305
18	Other (provide details in footnote):		
18.1	Other: Margin and Customer Deposits	34,250,881	(31,941,646)
18.2	Other: Operating	(11,585,304)	(52,360,690)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,102,218,800	776,981,263
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,200,320,722)	(1,291,637,940)

STATEMENT OF CASH FLOWS

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)
27	Gross Additions to Nuclear Fuel	0	0
28	Gross Additions to Common Utility Plant	0	0
29	Gross Additions to Nonutility Plant	23	(23)
30	(Less) Allowance for Other Funds Used During Construction	(17,686,684)	(23,190,377)
31	Other (provide details in footnote):		
31.1	Other Capital Activities	(12,177,514)	(32,948,158)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,194,811,529)	(1,301,395,744)
36	Acquisition of Other Noncurrent Assets (d)	0	0
37	Proceeds from Disposal of Noncurrent Assets (d)		0
39	Investments in and Advances to Assoc. and Subsidiary Companies	(944,682)	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)	0	0
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased	0	0
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables	0	0
50	Net (Increase) Decrease in Inventory	0	0
51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Sale of Property	0	0
53.2	Other Investments	7,043,855	5,296,755
53.3	Purchases of Trojan Decommissioning Securities	(8,608,517)	(7,836,629)
53.4	Sales of Trojan Decommissioning Securities	3,509,324	1,998,350
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,193,811,549)	(1,301,937,268)

STATEMENT OF CASH FLOWS

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)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	310,000,000	670,000,000
62	Preferred Stock		
63	Common Stock	244,331,270	341,136,729
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	0	0
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	554,331,270	1,011,136,729
72	Payments for Retirement of:		
73	Long-term Debt (b)	(170,000,000)	(130,000,000)
74	Preferred Stock	0	0
75	Common Stock	0	0
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	0	0
76.2	Debt Issue Costs	(4,196,683)	(3,084,323)
78	Net Decrease in Short-Term Debt (c)	0	(145,811,136)
80	Dividends on Preferred Stock	0	0
81	Dividends on Common Stock	(224,972,331)	(199,490,742)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	155,162,256	532,750,528
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)	63,569,507	7,794,523
88	Cash and Cash Equivalents at Beginning of Period	12,460,719	4,666,196
90	Cash and Cash Equivalents at End of Period	76,030,226	12,460,719

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to increase in depreciation expense.

(b) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

(c) Concept: InvestmentsInAndAdvancesToAssociatedAndSubsidiaryCompanies

Amount relates to intercompany balance from dissolved subsidiary.

(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to increase in deferred investment tax credits

(e) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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NOTES TO FINANCIAL STATEMENTS

- 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.
- 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.
- 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.
- 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.
- Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
- 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.
- 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.
- 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, where material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
- 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)	\$ 460,719	\$ 17,030,226
Temporary Cash Investments (136)	12,000,000	59,000,000
	\$ 12,460,719	\$ 76,030,226
	2024	2025
Cash paid during the year:		
Interest	\$ 188,977,140	\$ 209,304,878
Allowance for borrowed funds used during construction	(15,344,389)	(11,263,956)
	\$ 173,632,751	\$ 198,040,922
Income taxes (received)	\$ (89,805,127)	\$ (162,055,996)

Non-cash investing and financing activities:

Accrued capital additions	\$	184,079,067	\$	126,462,149
	\$	57,371,089	\$	62,844,522
Accrued dividends payable				
Preliminary engineering transferred to Construction work in progress	\$	2,535,276	\$	4,546,614

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, natural gas, and environmental credits 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 4,000 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, 2025, PGE served approximately 960,000 retail customers with a service area population of approximately 2 million.

As of December 31, 2025, PGE had 2,877 employees in its workforce, with 666 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. One agreement covers 602 employees and expires February 2028, and the other covers 64 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, 2025 up to February 17, 2026, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 13, 2026. 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 \$59 million as of December 31, 2025 and \$12 million as of December 31, 2024 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 eight calendar 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 53 business days after the due date of the final invoice.

Provisions for Uncollectible Accounts receivable 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 receivable and unbilled revenues see "*Customer Accounts Receivable, Net*" in Note 3, Comparative Balance Sheet Components.

Provisions for Uncollectible Accounts receivable 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. The balance of provisions for uncollectible accounts receivable was immaterial and there have been no material write-offs of Customer Accounts Receivable related to wholesale sales in 2025 or 2024.

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 prices. 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 \$116 million as of December 31, 2025 and \$125 million as of December 31, 2024. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and there were \$123 million and \$18 million as of December 31, 2025 and 2024, 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 allocable overheads such as engineering, supervision, employee benefits, certain administrative costs directly related to construction, 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 related to recently completed plant that are 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 (GRC) for equity funds and the cost of actual borrowings for debt funds. AFUDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 6.7% in 2025 and in 2024. AFUDC from borrowed funds, reflected as a reduction to Interest Charges, was \$11 million in 2025 and \$15 million in 2024. AFUDC from equity funds, included in Other Income, was \$18 million in 2025 and \$23 million in 2024.

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 3.6% in 2025, and 3.5% in 2024 and 3.4% in 2023. 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.

Generation plants are depreciated using a life-span methodology, which is designed to recover the plant investment by the estimated retirement dates, which range from 2035 to 2064. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Transmission	58
Distribution	50
Energy Storage	16
General	17

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 three, 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 \$622 million and \$611 million as of December 31, 2025 and 2024, respectively, with amortization expense of \$76 million in 2025 and \$72 million in 2024. Future estimated amortization expense as of December 31, 2025 is as follows: \$79 million in 2026; \$73 million in 2027; \$49 million in 2028; \$29 million in 2029; and \$17 million in 2030.

Marketable Securities

Nuclear decommissioning trust

The Nuclear decommissioning trust (NDT) 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 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

PGE's non-qualified benefit plans (NQBP) reflects assets held in trust to cover the obligations of PGE's 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.

Other Investments

PGE has investments in non-marketable equity securities for which the Company does not have controlling financial interest however, based on PGE's ownership interest, are accounted for under the equity method of accounting. These investments are accounted for at cost, adjusted for the Company's proportionate share of the investee's earnings or losses, distributions received, and impairments, if any.

As of December 31, 2025 and 2024, equity method investments were \$19 million and \$13 million, respectively, recorded in Other noncurrent assets on the Company's Comparative Balance Sheet. For the years ended December 31, 2025 and 2024, the Company's share of net earnings or losses from equity method investments were immaterial. PGE's share of earnings or losses are recorded within Other Income on the Company's Statement of Income.

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: i) probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process; or ii) current collections for future expected costs. 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 verify 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 includes 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 9.34% for 2025 and 9.5% for 2024.

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, 2025, PGE's actual NVPC was \$6 million below baseline NVPC, which is within the established deadband range. Accordingly, there is no estimated refund to customers under the PCAM for 2025. For the year ended December 31, 2024, actual NVPC was below baseline NVPC by \$78 million, which was outside the established deadband range. Pursuant to the PCAM and related earnings test, because PGE's preliminary regulatory ROE was below 10.5%, there was no estimated refund to customers under the PCAM for 2024.

The Company also has a reliability contingency event (RCE) mechanism, which operates under the PCAM tariff. This mechanism was approved by the OPUC as part of the 2024 GRC proceedings. The RCE mechanism allows PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's Annual Power Cost Update Tariff (AUT), without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. This mechanism expired at the end of 2025.

For additional information concerning PCAM, see Note 6, Regulatory Assets and Liabilities.

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, net 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 Depreciation and amortization expense 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 Expense and the amount included in customer prices is recorded as a regulatory asset or liability in the Company's Comparative Balance Sheet. As of December 31, 2025, PGE had a net regulatory asset related to Utility Plant AROs in the amount of \$6 million and a net regulatory asset related to Trojan decommissioning ARO activities of \$161 million. As of December 31, 2024, 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 \$161 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 NQBP 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 \$70 million in 2025 and \$63 million in 2024.

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 included in Customer Accounts Receivable, 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 Revenue 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.

Time-based and performance-based restricted stock unit (RSU) grant agreements provide that, if a grantee satisfies the "rule of 75" upon termination of employment for reasons other than cause, then: i) in the case of time-based RSUs, all unvested awards will vest; and ii) in the case of performance-based RSUs, the grantee will be eligible for full vesting, based on performance results, notwithstanding early termination. For purposes of these provisions, a recipient satisfies the rule of 75 if the recipient has no less than 5 years of service and the recipient's age plus years of service is at least 75. PGE accelerates recognition of compensation cost to the date the rule of 75 is met if the date is earlier than the vesting date of the award.

For additional information concerning the Company's Stock-Based Compensation, see Note 13, Stock-Based Compensation.

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. The weighted average life of the related properties is 16 years as of December 31, 2025. 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 Other 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 has elected an accounting policy to account for the transfer of Federal production tax credits (PTCs) and ITCs, including discounts, within the scope of Accounting Standards Codification 740 - Income Taxes. Tax credit sales are classified as an operating activity in the statements of cash flows, and included in Cash paid for income taxes, net within the supplemental disclosures of cash flow information. Derecognition of the transferred deferred tax asset occurs when the buyer obtains control of the tax credit.

Recently Adopted Accounting Pronouncements

For the year ended December 31, 2025, PGE adopted Accounting Standards Update (ASU) 2023-09 *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*. ASU 2023-09 amends Topic 740 to require entities to annually disaggregate the income tax rate reconciliation into prescribed categories, as well as to disclose income taxes paid disaggregated by jurisdiction. Because PGE elected to apply the guidance retrospectively, items for prior periods were reclassified to conform with current year presentation. As the standard relates only to disclosures, the adoption did not have a material impact on PGE's results of operation, financial position, or cash flows. For new required disclosures and further information, see Note 11, Income Taxes.

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,	
	2025	2024
Balance as of beginning of year	\$ 12	\$ 9
Increase in provision	12	11
Amounts written off, less recoveries	(11)	(8)
Balance as of end of year	\$ 13	\$ 12

Net Utility Plant

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

	As of December 31,	
	2025	2024
Utility Plant ⁽¹⁾ :		

Generation		\$	5,540	\$	5,456
Transmission ⁽²⁾			1,602		1,400
Distribution ⁽²⁾			6,248		6,191
General			1,639		986
Energy storage			896		-
Intangible			205		1,007
Total in service			16,130		15,040
Accumulated Provision for Depreciation, Amortization, and Depletion and amortization			(6,556)		(6,196)
Total in service, net			9,574		8,844
Held for future use			88		72
Construction Work In Progress			415		570
Utility Plant, net		\$	10,077	\$	9,486

(1) On January 1, 2025, FERC Order 898 reclassified certain assets between primary functions for ratemaking purposes. In 2025 and going forward, tangible assets are classified consistent with the FERC's updated functional classification. Reclassifications were completed as of January 1, 2025 of \$22 million of Generation, \$21 million of Transmission, \$87 million of Distribution, \$(132) million of General, and \$2 million of Energy storage plant.

(2) On July 2, 2025, the FERC approved PGE's request to classify the functional asset classification of certain 57kV facilities from Distribution to Transmission to align classification with the primary function of these assets. As a result, PGE reclassified \$84 million of Utility Plant in-service assets from Distribution to Transmission.

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, 2025 and 2024, 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, 2025				
	Level 1	Level 2	Level 3	Other ⁽²⁾	Total
Assets:					
Temporary Cash Investments	\$ 59	\$ --	\$ --	\$ --	\$ 59
Nuclear decommissioning trust: ⁽¹⁾					
Debt securities:					
Domestic government	14	11	--	--	25
Corporate credit	--	10	--	--	10
Money market funds measured at NAV ⁽²⁾	--	--	--	7	7
Non-qualified benefit plan trust: ⁽³⁾					
Debt securities--domestic government	1	--	--	--	1
Paid Leave Oregon Trust:					
Money market funds measured at NAV ⁽²⁾	--	--	--	7	7
Price risk management activities: ⁽¹⁾⁽⁴⁾					
Electricity	--	29	1	--	30
Natural gas	--	3	--	--	3
	<u>\$ 74</u>	<u>\$ 53</u>	<u>\$ 1</u>	<u>\$ 14</u>	<u>\$ 142</u>
Liabilities:					
Price risk management activities: ⁽¹⁾⁽⁴⁾					
Electricity	\$ --	\$ 13	\$ 37	\$ --	\$ 50
Natural gas	--	160	4	--	164
	<u>\$ --</u>	<u>\$ 173</u>	<u>\$ 41</u>	<u>\$ --</u>	<u>\$ 214</u>

(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 \$35 million, which are recorded at cash surrender value.

(4) For further information regarding price risk management derivatives, see Note 5, Risk Management.

	December 31, 2024				
	Level 1	Level 2	Level 3	Other ⁽²⁾	Total
Assets:					
Temporary Cash Investments	\$ 12	\$ --	\$ --	\$ --	\$ 12
Nuclear decommissioning trust: ⁽¹⁾					
Debt securities:					
Domestic government	10	6	--	--	16
Corporate credit	--	7	--	--	7
Money market funds measured at NAV ⁽²⁾	--	--	--	7	7
Non-qualified benefit plan trust: ⁽³⁾					
Debt securities--domestic government	2	--	--	--	2
Paid Leave Oregon Trust:					
Money market funds measured at NAV ⁽²⁾	--	--	--	4	4
Price risk management activities: ⁽¹⁾⁽⁴⁾					
Electricity	--	18	1	--	19
Natural gas	--	15	--	--	15
	<u>\$ 24</u>	<u>\$ 46</u>	<u>\$ 1</u>	<u>\$ 11</u>	<u>\$ 82</u>
Liabilities:					
Price risk management activities: ⁽¹⁾⁽⁴⁾					
Electricity	\$ --	\$ 25	\$ 31	\$ --	\$ 56
Natural gas	--	159	4	--	163
	<u>\$ --</u>	<u>\$ 184</u>	<u>\$ 35</u>	<u>\$ --</u>	<u>\$ 219</u>

(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 \$32 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.

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 money market funds in the NDT and Paid Leave Oregon Trust are 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		Valuation Technique	Significant Unobservable Input	Price per Unit		
	Assets	Liabilities			Low	High	Weighted Average
(in millions)							
As of December 31, 2025:							
Electricity physical forwards	\$ --	\$ 37	Discounted cash flow	Electricity forward price (per MWh)	\$ 22.99	\$ 94.65	\$ 59.28
Natural gas financial swaps	--	4	Discounted cash flow	Natural gas forward price (per Dth)	1.67	2.76	2.15
Electricity financial futures	1	--	Discounted cash flow	Electricity forward price (per MWh)	31.00	84.00	52.13
	<u>\$ 1</u>	<u>\$ 41</u>					
As of December 31, 2024:							
Electricity physical forwards	\$ --	\$ 28	Discounted cash flow	Electricity forward price (per MWh)	\$ 14.00	\$ 99.68	\$ 59.43
Natural gas financial swaps	--	4	Discounted cash flow	Natural gas forward price (per Dth)	1.86	6.53	2.68
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	27.00	110.00	70.55
	<u>\$ 1</u>	<u>\$ 35</u>					

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,	
	2025	2024
Net liabilities from price risk management activities as of beginning of year	\$ 34	\$ 45
Net realized and unrealized losses *	22	25
Net transfers from Level 3 to Level 2	(16)	(36)
Net liabilities from price risk management activities as of end of year	<u>\$ 40</u>	<u>\$ 34</u>
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	<u>\$ 27</u>	<u>\$ 30</u>

* Includes \$5 million in net realized gains in both 2025 and 2024.

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, 2025 and 2024, 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, 2025, the carrying amount of PGE's long-term debt was \$4,679 million and its estimated aggregate fair value was \$4,311 million. As of December 31, 2024, the carrying amount of PGE's long-term debt was \$4,539 million with an estimated aggregate fair value of \$3,963 million.

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

NOTE 5: 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 and sells environmental credits in the wholesale marketplace. 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,	
	2025	2024
Current assets:		
Commodity contracts:		
Electricity	\$ 29	\$ 18
Natural gas	3	14
Total current derivative assets	<u>32</u>	<u>32</u>
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Natural gas	--	1
Total noncurrent derivative assets	<u>1</u>	<u>2</u>
Total derivative assets	<u>\$ 33</u>	<u>\$ 34</u>
Current liabilities:		
Commodity contracts:		
Electricity	\$ 19	\$ 32
Natural gas	139	115
Total current derivative liabilities	<u>158</u>	<u>147</u>
Noncurrent liabilities:		
Commodity contracts:		
Electricity	31	24
Natural gas	25	48
Total noncurrent derivative liabilities	<u>56</u>	<u>72</u>
Total derivative liabilities	<u>\$ 214</u>	<u>\$ 219</u>

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 December 31, 2035, were as follows (in millions):

	As of December 31,			
	2025		2024	
Commodity contracts:				
Electricity	1	MWh	2	MWh
Natural gas	224	Dth	199	Dth
Foreign currency contracts	\$ 9	Canadian	\$ 34	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, 2025, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were \$41 million, all of which was for natural gas, for which PGE has posted \$14 million collateral. As of December 31, 2024, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were \$41 million, entirely for natural gas, for which PGE had posted \$16 million 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,	
	2025	2024
Commodity contracts:		
Electricity	\$ (26)	\$ (17)
Natural Gas	206	30
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 gains of \$24 million and \$5 million for the years ended December 31, 2025 and 2024, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized losses recorded as of December 31, 2025 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2026	2027	2028	2029	2030	Thereafter	Total
Commodity contracts:							
Electricity	\$ (9)	\$ 2	\$ 4	\$ 3	\$ 3	\$ 17	\$ 20
Natural gas	136	20	3	2	--	--	161
Net unrealized loss	\$ 127	\$ 22	\$ 7	\$ 5	\$ 3	\$ 17	\$ 181

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, 2025 was \$208 million. The Company has posted \$72 million in collateral, consisting of \$59 million of cash and \$13 million of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2025, the cash requirement to either post as collateral or settle the instruments immediately would have been \$146 million. As of December 31, 2025, PGE had no 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 Current and Accrued Assets on the Company's Comparative Balance Sheet.

As of December 31, 2025, PGE received from counterparties \$26 million in collateral, consisting of \$5 million of letters of credit and \$21 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 5, 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,	
		2025	2024
		Total	Total
Regulatory assets:			
Price risk management	(1)	\$ 181	\$ 185
Pension plans	(2)	64	84
Deferred income taxes	(5)	50	59
February 2021 ice storm and damage	2029	47	59
January 2024 storm and damage	(3)	50	47
Reliability contingency events	(3)	94	92
2020 Labor Day wildfire	2029	19	24
Wildfire mitigation	(4)	42	44
Other	Various	123	130
Total regulatory assets		\$ 670	\$ 724
Regulatory liabilities:			
Deferred income taxes	(5)	278	237
Clearwater RAC	(6)	22	40
Other	Various	52	44
Total regulatory liabilities		\$ 352	\$ 321

- (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 period has yet to be decided.
- (4) The current portion of the balance is expected to amortize by May 31, 2026. The non-current portion of the balance relates to incremental amounts deferred between January 1, 2024 and December 31, 2025 and are not yet approved for amortization.
- (5) 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.
- (6) Amortization began on March 1, 2025.

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.

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.

January 2024 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 storm that ultimately led Oregon's Governor to declare a state of emergency in January 2024. The declared state of emergency allows PGE to seek recovery of incremental storm expenses through the OPUC pre-authorized emergency deferral mechanism, subject to the application of an earnings test. 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 through December 31, 2025 the Company has deferred \$48 million, including interest, under the deferral. PGE believes the amounts deferred as of December 31, 2025 are probable of recovery under the emergency deferral mechanism, and no earnings test adjustment is necessary as PGE's 2024 regulated return on equity did not exceed the OPUC's authorized rate. The OPUC has significant discretion in making the final determination of recovery and their conclusion of overall prudence, including application of the earnings test, could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

Reliability contingency events represents costs deferred under the reliability contingency event (RCE) mechanism, which allows PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's AUT, without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. As of December 31, 2025, PGE's deferred balance related to RCEs was \$90 million, which includes \$88 million related to RCEs deferred in 2024 and \$2 million related to RCEs deferred in 2025. PGE files the results of the PCAM annually with the OPUC no later than July 1, initiating a regulatory review process that typically results in a final determination and order from the OPUC by the end of the year of filing, with any resulting refund or collection impacting customer prices effective in the following year. RCE costs incurred in 2024 and in 2025 will be included in the PCAM for 2024 and 2025. The Company filed the PCAM for 2024 on July 1, 2025, and the proceeding is on-going with a Commission decision anticipated in the first quarter of 2026. The Company expects to file the PCAM for 2025 no later than July 1, 2026. PGE believes the deferred amounts as of December 31, 2025 are probable of recovery. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

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.

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 Oregon Senate Bill 762, enacted in 2021. These efforts include enhanced tree and brush clearing, hardening and undergrounding equipment, and making emergency plans in close partnership with various land and emergency management agencies to further expand the use of a public safety power shutoff, when the risk warrants. In December 2025, PGE submitted its 2026-2028 risk-based Wildfire Mitigation Plan. This plan is subject to annual updates, as well as the OPUC's approval.

As of December 31, 2025 and December 31, 2024, PGE's deferred balance related to wildfire mitigation was \$42 million and \$43 million, respectively. The 2025 balance is comprised of:

- *2024 AAC*--Beginning January 1, 2024, and in conjunction with the Company's 2024 GRC proceeding, PGE removed the \$24 million of wildfire mitigation operations and maintenance (O&M) expense recovery from base rates, with the intent of recovering the current year forecasted O&M expense within the automatic adjustment clause (AAC) in a separate tariff. On February 16, 2024, PGE submitted an advice filing to the OPUC to update the tariff to reflect prospective wildfire mitigation costs for 2024, which included \$45 million of O&M expense and \$4 million for the revenue requirement of capital placed in service. On July 23, 2024, the OPUC reached a decision that allowed PGE to begin collecting \$24 million of O&M expense and \$4 million for the revenue requirement of capital placed in service. Collection will occur over a nine-month period, which began August 1, 2024. Although the approved amount of collections in 2024 is less than actual costs, PGE does not believe it is precluded from deferring such costs and believes they are prudently incurred and probable of recovery. Any differences between actual expense and customer collections will be recorded as regulatory assets or liabilities within the AAC balancing account, which will be subject to a prudence review, but will not be subject to an earnings test. As of December 31, 2025, there was \$23 million deferred as a regulatory asset in the balancing account related to 2024. PGE submitted an additional filing to seek recovery of the remaining O&M expense on October 17, 2025. On February 13, 2026, PGE filed a Stipulation reflecting an all-party settlement that, if approved by the OPUC, would allow PGE recovery of its deferred amounts related to 2024 O&M. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.
- *2025 AAC*--In conjunction with PGE's filed 2025 Wildfire Mitigation Plan, PGE submitted a series of advice filings in 2025 with the intent of recovering the \$56 million related to O&M and \$12 million related to the capital revenue requirement in a two-phased approach. The first phase, which includes \$24 million of O&M to be collected over a twelve-month period, was approved by the OPUC in February 2025, with a tariff effective date of March 1, 2025. The second phase, which was approved by the OPUC in May 2025, will be collected over a twelve-month period beginning June 1, 2025, and includes \$12 million of O&M and the entire \$12 million related to capital revenue requirement. Although the OPUC has only approved a portion of PGE's 2025 wildfire mitigation O&M, PGE does not believe it is precluded from deferring such costs. Any differences between actual expense and customer collections will be recorded as regulatory assets or liabilities within the AAC balancing account, which will be subject to a prudence review, but will not be subject to an earnings test. As of December 31, 2025, there was \$19 million deferred as a regulatory asset in the balancing account related to 2025. PGE submitted an additional filing to seek recovery of the remaining 2025

forecasted O&M expense on October 17, 2025. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

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.

Clearwater RAC represents all costs and benefits associated with the Clearwater wind facility. Under the Renewable Adjustment Clause (RAC), during 2023, the Company submitted a filing for Clearwater proposing to defer the revenue requirement, net of NVPC benefits, from the in-service date of January 2024 until Clearwater was reflected in customer prices, which was March 1, 2025. For the year ended December 31, 2024, PGE deferred the revenue requirement, net of NVPC benefits resulting in a net regulatory liability of \$40 million, which began amortizing as a refund to customers on March 1, 2025 over a twelve-month period, as approved in OPUC Order 25-075 issued February 21, 2025. For the period of January 1, 2025 through December 31, 2025, PGE deferred an additional net \$13 million regulatory liability, which remains subject to a future regulatory review, representing the deferred revenue requirement that PGE believes is probable of recovery, net of NVPC that is probable of refund to customers under the RAC for that period. The OPUC has significant discretion on overall prudence and in making the final determination of recovery or refund. Any cost disallowance or increased refunds would be recognized as a charge to earnings.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2025	2024
Trojan decommissioning activities	\$ 208	\$ 205
Utility Plant	75	80
Non-utility property	29	25
Total asset retirement obligations	312	310
Less: current portion	13	18
Noncurrent asset retirement obligations	\$ 299	\$ 292

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 U.S. Department of Energy (USDOE) facility is complete, which is not expected prior to 2059. In 2025, the Company recorded an increase in the ARO of \$2 million due to an increase in expected annual ISFSI operation costs. The Company also recorded Accretion Expense of \$9 million and a reduction of \$8 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 \$10 million in 2025 for costs incurred in 2024 and \$22 million in 2024 for costs incurred in 2023 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 2025, utility AROs decreased by \$5 million, with the change comprised of Accretion Expense of \$3 million, and a reduction of \$8 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,	
	2025	2024
Balance as of beginning of year	\$ 310	\$ 286
Liabilities incurred	--	--
Liabilities settled	(13)	(16)
Accretion Expense	13	12
Revisions in estimated cash flows	2	28
Balance as of end of year	\$ 312	\$ 310

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 NDT 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 September 10, 2025, PGE entered into an amendment of its existing revolving credit facility that extended the scheduled expiration into September 2030. As of December 31, 2025, PGE had a \$750 million revolving credit facility that provides the Company the ability to expand 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, 2025, PGE was in compliance with this covenant with a 53.0% debt to total capital ratio.

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, 2025, PGE had no commercial paper outstanding.

Under the revolving credit facility, as of December 31, 2025, 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.

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 \$192 million of letters of credit were outstanding as of December 31, 2025. 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, 2028.

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

	Year Ended December 31,	
	2025	2024
Average daily amount of short-term debt outstanding	\$ 21	\$ 39
Weighted daily average interest rate *	4.6%	5.5%
Maximum amount outstanding during the year	\$ 180	\$ 319

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

NOTE 9: LONG-TERM DEBT AND OTHER FINANCING ARRANGEMENTS

Long-term debt

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

	As of December 31,	
	2025	2024
First Mortgage Bonds , rates range from 1.82% to 6.88%, with a weighted average rate of 4.60% in 2025 and 4.52% in 2024, due at various dates through 2059.	\$ 4,560	\$ 4,250
Unsecured term bank loan	--	170
Pollution Control Revenue Bonds , rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	4,679	4,539
Less: Unamortized debt expense	(17)	(15)
Less: Current portion of long-term debt	--	(170)
Long-term debt, net of current portion	\$ 4,662	\$ 4,354

First Mortgage Bonds--On March 25, 2025, PGE entered into a Bond Purchase Agreement related to the sale of \$310 million in FMBs. The Bonds were issued and funded in full on March 25, 2025 and consist of:

- a series, due in 2035, in the amount of \$60 million that will bear interest from its issuance date at an annual rate of 5.36%;
- a series, due in 2045, in the amount of \$50 million that will bear interest from its issuance date at an annual rate of 5.72%; and
- a series, due in 2055, in the amount of \$200 million that will bear interest from its issuance date at an annual rate of 5.84%.

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 November 14, 2024, PGE obtained a 366-day term loan from lenders in the aggregate principal of \$300 million under a 366-Day Bridge Credit Agreement. Pursuant to the Agreement, on November 14, 2024, PGE drew a loan from the lenders in the aggregate principal of \$220 million. 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 80.0 basis points. The interest rate was subject to adjustment pursuant to the terms of the loan. On December 31, 2024, PGE repaid \$50 million of the term loan. On March 31, 2025, the Company repaid another \$102 million, and on October 27, 2025 repaid the remaining balance of \$68 million, repaying the loan in full.

Pollution Control Revenue Bonds--In March 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 that bear an interest rate of 2.125%, and \$21 million aggregate principal 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, 2025, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:

2026	\$	--
2027		160
2028		100
2029		200
2030		325
Thereafter		3,894
	\$	<u>4,679</u>

Pelton/Round Butte financing arrangement

Under terms of an 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 in 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 records the tangible utility asset within Net Utility Plant on the Comparative Balance Sheet as if it were the legal owner and recognizes Depreciation 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. 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.

As of December 31, 2025, the future minimum payments on the financing arrangement are as follows (in millions):

Years ending December 31:

2026	\$	5
2027		5
2028		5
2029		5
2030		5
Thereafter		55
Total Payments		<u>80</u>
Less: Imputed Interest		(49)
Present value of minimum payments	\$	<u>31</u>

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 \$22 million in contributions to the pension plan in 2025 and \$16 million in 2024. PGE expects to contribute \$27 million to the pension plan in 2026.

PGE executed an annuity contract purchase in January 2025 to settle future benefit obligations for a portion of the defined benefit pension plan. The annuity contract purchase, in combination with elevated lump sum benefit elections throughout 2025, resulted in a \$4 million settlement loss, which has been recorded in Miscellaneous income (expense), net on the Statement of Income.

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.

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 in Other Special Funds in PGE's Comparative Balance Sheet are as follows as of December 31 (in millions):

	2025			2024		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	\$ 15	\$ 21	\$ 36	\$ 16	\$ 18	\$ 34
Non-qualified benefit plan liabilities	15	57	72	16	60	76

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,			
	2025		2024	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Growth securities	55%	55%	53%	55%
Liability Hedging Fixed Income securities	45	45	47	45
Total	100	100	100	100
Other Postretirement Benefit Plans:				
Equity securities	40%	39%	40%	38%
Debt securities	60	61	60	62
Total	100	100	100	100
Non-Qualified Benefits Plans:				
Equity securities	1%	1%	1%	2%
Debt securities	2	2	6	5
Insurance contracts	97	97	93	93
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, 2025:					
Defined Benefit Pension Plan assets:					
Equity securities--Domestic	\$ 13	\$ --	\$ --	\$ --	\$ 13
Investments measured at NAV:					
Money market funds	--	--	--	5	5
Collective trust funds	--	--	--	473	473
Private equity funds	--	--	--	1	1
	\$ 13	\$ --	\$ --	\$ 479	\$ 492
Other Postretirement Benefit Plans assets:					
Equity securities:					
Domestic	--	2	--	--	2
International	5	--	--	--	5
Debt securities--Domestic	--	5	--	--	5
Investments measured at NAV:					
Money market funds	--	--	--	12	12
Collective trust funds	--	--	--	4	4
	\$ 5	\$ 7	\$ --	\$ 16	\$ 28
As of December 31, 2024:					
Defined Benefit Pension Plan assets:					
Equity securities--Domestic	\$ 13	\$ --	\$ --	\$ --	\$ 13
Investments measured at NAV:					
Money market funds	--	--	--	30	30
Collective trust funds	--	--	--	440	440
Private equity funds	--	--	--	1	1
	\$ 13	\$ --	\$ --	\$ 471	\$ 484
Other Postretirement Benefit Plans assets:					
Equity securities:					
Domestic	--	2	--	--	2
International	4	--	--	--	4
Debt securities--Domestic government	--	4	--	--	4
Investments measured at NAV:					
Money market funds	--	--	--	11	11
Collective trust funds	--	--	--	4	4
	\$ 4	\$ 6	\$ --	\$ 15	\$ 25

* 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 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-backed securities, 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, 2025 and 2024. Information related to the Other NQBP is not included in the following tables (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2025	2024	2025	2024	2025	2024
Benefit obligation:						
As of January 1	\$ 612	\$ 690	\$ 37	\$ 35	\$ 16	\$ 18
Service cost	10	10	1	1	--	--
Interest cost	32	33	2	2	1	--
Actuarial (gain) loss	7	(40)	--	1	1	--
Benefits paid from plan assets	(29)	(78)	(2)	(3)	(3)	(2)
Administrative expenses	(3)	(3)	--	--	--	--
Plan settlements	(40)	--	--	--	--	--
Special/contractual termination benefits	--	--	--	1	--	--
As of December 31	<u>\$ 589</u>	<u>\$ 612</u>	<u>\$ 38</u>	<u>\$ 37</u>	<u>\$ 15</u>	<u>\$ 16</u>
Fair value of plan assets:						
As of January 1	\$ 484	\$ 530	\$ 25	\$ 23	\$ 16	\$ 17
Actual return on plan assets	58	19	3	2	(1)	(1)
Company contributions	22	16	2	3	3	2
Benefit payments	(29)	(78)	(2)	(3)	(3)	(2)
Administrative expenses	(3)	(3)	--	--	--	--
Plan settlements	(40)	--	--	--	--	--
As of December 31	<u>\$ 492</u>	<u>\$ 484</u>	<u>\$ 28</u>	<u>\$ 25</u>	<u>\$ 15</u>	<u>\$ 16</u>
Unfunded position as of December 31	<u>\$ (97)</u>	<u>\$ (128)</u>	<u>\$ (10)</u>	<u>\$ (12)</u>	<u>\$ --</u>	<u>\$ --</u>
Accumulated benefit plan obligation as of December 31	<u>\$ 551</u>	<u>\$ 574</u>	<u>N/A</u>	<u>N/A</u>	<u>\$ 15</u>	<u>\$ 16</u>
Classification in Comparative Balance Sheet:						
Noncurrent asset	\$ --	\$ --	\$ --	\$ --	\$ 15	\$ 16
Current liability	--	--	--	(1)	(2)	(2)
Noncurrent liability	(97)	(128)	(10)	(11)	(13)	(14)
Net asset (liability)	<u>\$ (97)</u>	<u>\$ (128)</u>	<u>\$ (10)</u>	<u>\$ (12)</u>	<u>\$ --</u>	<u>\$ --</u>
Amounts included in comprehensive income:						
Net actuarial loss (gain)	\$ (16)	\$ (20)	\$ (2)	\$ --	\$ 1	\$ --
Net settlement (loss)	(4)	--	--	--	--	--
Amortization of net actuarial gain (loss)	--	--	--	--	(1)	(1)
	<u>\$ (20)</u>	<u>\$ (20)</u>	<u>\$ (2)</u>	<u>\$ --</u>	<u>\$ --</u>	<u>\$ (1)</u>
Amounts included in AOCL: *						
Net actuarial loss (gain)	\$ 65	\$ 85	\$ (5)	\$ (3)	\$ 6	\$ 6
Prior service cost	(1)	(1)	--	--	--	--
	<u>\$ 64</u>	<u>\$ 84</u>	<u>\$ (5)</u>	<u>\$ (3)</u>	<u>\$ 6</u>	<u>\$ 6</u>

* 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 \$7 million and a gain of \$40 million, and the changes between actual and expected return on plan assets were a gain of \$23 million and a loss of \$20 million, for the years ended December 31, 2025 and 2024, respectively.
- For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were an

immaterial loss and a loss of \$1 million, and the changes between actual and expected return on plan assets were a gain of \$2 million and a gain of \$1 million, for the years ended December 31, 2025 and 2024, 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	
	2025	2024	2025	2024	2025	2024
Service cost	\$ 10	\$ 10	\$ 1	\$ 1	\$ --	\$ --
Interest cost on benefit obligation	32	33	2	2	1	--
Expected return on plan assets	(36)	(39)	(1)	(1)	--	--
Amortization of prior service credit	--	--	--	--	--	--
Amortization of net actuarial loss (gain)	--	--	--	--	1	1
Settlement loss (gain)	4	--	--	--	--	--
Net periodic benefit cost	<u>\$ 10</u>	<u>\$ 4</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 1</u>

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		
	2025	2024	2025	2024	2025	2024	
Assumptions used to determine benefit obligations:							
Discount rate	5.56%	5.70%	5.29%	5.59%	5.56%	5.70%	
Rate of compensation increase	4.14%	4.08%	4.03%	4.02%	3.96%	3.98%	
Assumptions used to determine net periodic benefit cost:							
Discount rate	5.70%	5.13%	5.59%	5.18%	5.70%	5.13%	
Rate of compensation increase	4.08%	4.19%	4.02%	4.06%	3.98%	4.01%	
Long-term rate of return on plan assets	6.88%	6.88%	4.78%	4.73%	N/A	N/A	

As of December 31, 2025, 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. 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.

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					
	2026	2027	2028	2029	2030	2031 - 2035
Defined benefit pension plan	\$ 44	\$ 44	\$ 44	\$ 44	\$ 43	\$ 219
Other postretirement benefits	4	4	4	5	4	11
Non-qualified benefit plans	2	2	2	2	2	6
Total	<u>\$ 50</u>	<u>\$ 50</u>	<u>\$ 50</u>	<u>\$ 51</u>	<u>\$ 49</u>	<u>\$ 236</u>

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 7% of the employee's base pay and also contributes 1% of the employee's base pay, whether or not the employee contributes to the 401(k) Plan as a profit share.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company adds an additional 1% of the employee's base salary to their profit share.

For eligible employees who are not covered by PGE's defined benefit pension plan, the Company matches employee contributions up to 6% of the employee's base pay, and also contributes up to 7% of the employee's base pay as a profit share.

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 \$42 million in 2025 and \$37 million in 2024.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2025	2024
Current:		
Federal	\$ 3	\$ 2
State and local	13	12
	<u>16</u>	<u>14</u>

Deferred:		
Federal	19	(2)
State and local	26	23
	<u>45</u>	<u>23</u>
Investment Tax Credits	(8)	--
Income tax expense	<u>\$ 53</u>	<u>\$ 37</u>

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,			
	2025		2024	
Income before income taxes	\$ 359		\$ 350	
Federal statutory tax rate	76	21.0%	74	21.0%
State and local taxes, net of federal tax benefit ⁽¹⁾	30	8.4	28	8.0
Federal tax credits ⁽²⁾ :				
Energy-related tax credits	(48)	(13.3)	(58)	(16.6)
Research and development tax credits	(1)	(0.3)	(2)	(0.6)
Other credits	--	--	--	--
Nontaxable or Nondeductible Items:				
Executive Compensation ⁽³⁾	4	1.1	4	1.4
Other	--	--	1	0.2
Changes in Unrecognized Tax Benefits	--	--	1	0.2
Effect of ratemaking on income tax accounting ⁽⁴⁾	(8)	(2.1)	(11)	(2.9)
Effective tax rate	<u>\$ 53</u>	<u>14.8%</u>	<u>\$ 37</u>	<u>10.7%</u>

(1) State taxes in Oregon make up the majority (greater than 50 percent) of the tax effect in this category.

(2) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities as well as amortization of investment tax credits (ITCs). 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. PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation will end at various dates through 2034. The generation of PTCs from Tucannon River Wind Farm ended in 2024. ITCs are generated on qualifying renewable energy and infrastructure projects placed in service during 2023, 2024, and 2025. In accordance with the deferral method of accounting, ITCs are recorded as a deferred credit when generated and amortized as a reduction of income tax expense over the estimated useful life of the related properties. These energy-related tax credits are presented net of any transfer discounts. Federal tax credits also include 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.

(3) Under Internal Revenue Code Section 162(m), the tax deduction for compensation paid to certain executive officers is limited to \$1 million per year.

(4) The effect of ratemaking on income tax accounting primarily reflects excess deferred income taxes related to remeasurement under the Tax Cuts and Jobs Act. The majority of excess deferred income tax is subject to Internal Revenue Service 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,	
	2025	2024
Deferred Income Tax Assets:		
Employee benefits	\$ 79	\$ 89
Depreciation and amortization	321	310
Regulatory liabilities	21	33
Tax credits, net of transfer discount	61	69
Deferred investment tax credits	73	14
Price risk management	59	60
Other	6	4
Total deferred income tax assets	<u>620</u>	<u>579</u>
Deferred income tax liabilities:		
Depreciation and amortization	1,034	949
Price Risk Management	9	9
Regulatory assets	156	171
Other	24	16
Total Deferred Income Tax Liabilities	<u>1,223</u>	<u>1,145</u>
Accumulated Deferred Income Tax Liability, net	<u>\$ 603</u>	<u>\$ 566</u>

As of December 31, 2025, PGE has federal credit carryforwards of \$69 million. These credits primarily consist of PTCs, which will expire at various dates through 2045. In determining the need for a valuation allowance, PGE considered anticipated proceeds from the sale of tax credits. However, PGE believes it is more likely than not that its deferred income tax assets as of December 31, 2025 and 2024 will be realized. Accordingly, no material valuation allowance has been recorded. As of December 31, 2025, and 2024, PGE had no material unrecognized tax benefits.

On April 17, 2024, PGE received approval from the OPUC to transfer 2024 and 2025 PTCs and record any difference between the full value and the discounted value as a deferred regulatory asset. On August 20, 2025 and December 15, 2025, PGE received approval from the OPUC to transfer 2025 ITCs and return the net proceeds from the sale to PGE customers. PGE transferred tax credits, net of discounts, of \$179 million and \$112 million for cash proceeds in 2025 and 2024, respectively. The 2025 proceeds included \$37 million from PTC sales and \$142 million from ITC sales, net of discounts.

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 Internal Revenue Service 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. Supplemental cash flow information related to cash paid for income taxes consists of the following (in millions):

	Years Ended December 31,	
	2025	2024
Cash paid (received) for income taxes, net:		
Federal		
Federal income taxes paid	\$ 4	\$ 4
Tax credit sales	(179)	(112)
State and local		
Oregon	12	17
Other	1	1

NOTE 12: EQUITY-BASED PLANS

At-the-Market Offering Program

In July 2024, PGE entered into an equity distribution agreement under which it could sell up to \$400 million of its common stock through at-the-market offering programs. The Company entered into forward sale agreements for 5,756,432 shares and 1,420,049 shares in 2025 and 2024, respectively. In 2024, the Company issued 1,066,549 shares pursuant to the forward sale agreements and received net proceeds of \$50 million. During 2025, the Company issued 5,919,618 shares pursuant to the forward sale agreements and received net proceeds of \$250 million. The Company could have physically settled the remaining amount by delivering 190,314 shares in exchange for cash of \$8 million as of December 31, 2025. Any proceeds from the issuances of common stock will be used for general corporate purposes and investments in renewables and non-emitting dispatchable capacity.

Prior to settlement, the potentially issuable shares pursuant to the agreements will be considered 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 agreements 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. As of the year ended December 31, 2025, an incremental 5,025 shares were included in the calculation of diluted EPS related to the securities under the agreements.

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 1,125,000 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, 2025, there were 506,969 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, 2025, there were 2,451,588 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION

Pursuant to the Portland General Electric Company Stock Incentive Plan as amended and restated effective April 21, 2023 (the Plan), the Company may grant a variety of equity-based awards, including 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, 2023	645,697	47.57
Granted	478,509	41.02
Forfeited	(20,774)	45.32
Vested	(306,639)	44.76
Nonvested units as of December 31, 2024	796,793	44.78
Granted	582,444	41.68
Forfeited	(39,944)	42.48
Vested	(364,659)	47.31
Nonvested units as of December 31, 2025	974,634	42.58

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 779,123 shares remain available for future issuance as of December 31, 2025.

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 \$10 million for the year ended December 31, 2025 and \$8 million for 2024.

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 (ROE); 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 stockholder return (TSR) as a modifier to the total of the three equally-weighted metrics for 2023 and 2024 grants. For 2025 grants, ROE is replaced with TSR as one of the three equally-weighted metrics, and there is no modifier. 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:

	2025		2024	
Risk-free interest rate		4.4%		4.3%
Expected term (in years)		2.9		2.9
Volatility	15.5%	--	65.8%	12.4%
				53.2%

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 98.40% and 115.07% of awarded performance-based RSUs for the respective 2025 and 2024 grants, with an estimated 5% forfeiture rate on the grant date.

The total value of performance-based RSUs vested was \$8 million for the year ended December 31, 2025 and \$6 million for 2024.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was \$16 million for the year ended December 31, 2025 and \$24 million for 2024. 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 Stockholders' equity of \$4 million in 2025 and in 2024.

As of December 31, 2025, unrecognized stock-based compensation expense was \$9 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, 2025, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due							Total
	2026	2027	2028	2029	2030	Thereafter		
Capital and other purchase commitments	\$ 414	\$ 136	\$ 24	\$ 13	\$ 1	\$ 40	\$ 628	
Purchased Power:								
Electricity purchases	504	400	395	389	324	2,888	4,900	
Capacity contracts	218	128	129	130	125	618	1,348	
Public utility districts	10	9	7	1	1	13	41	
Natural gas	88	74	36	30	30	161	419	
Coal and transportation	38	38	38	38	--	--	152	
Total	\$ 1,272	\$ 785	\$ 629	\$ 601	\$ 481	\$ 3,720	\$ 7,488	

Capital and other purchase commitments--Certain commitments have been made for 2026 and beyond that include those related to hydro licenses, upgrades to generation, distribution, transmission and energy storage facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Subsequent to December 31, 2025, PGE has entered into agreements to construct two solar and battery hybrid projects for a total of 615 MW. These projects are not included in the table above and are summarized as follows:

- **Biglow Optimization**--PGE entered into an agreement to construct a 125 MW solar facility and a 125 MW BESS in Sherman County, Oregon. PGE will own the resource with an investment of approximately \$540 million, excluding AFUDC. The project has an estimated commercial operation date at the end of 2027.
- **Wheatridge Expansion**--PGE and NextEra Energy, Inc. entered into agreements to construct a 240 MW solar facility and a 125 MW BESS facility, located in Morrow County, Oregon. PGE will own 110 MW of solar and 65 MW of BESS production capacity with an investment of approximately \$490 million, excluding AFUDC. NextEra Energy, Inc. which operates the facility, owns the remaining 130 MW of solar and 60 MW of BESS production capacity and sells their portion of the output to PGE under a 30-year PPA. The project has an estimated commercial operation date at the end of 2027.

Electricity purchases and Capacity contracts--PGE has PPAs 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 on the Company's Statement of Income.

PGE has evaluated its long-term PPAs under variable interest entity accounting guidance. The Company has concluded that it either has no variable interest in the PPAs or, where variable interests exist, PGE is not the primary beneficiary. As a result, consolidation of these entities is not required. This determination is based on PGE lacking both control over significant activities and obligation to absorb losses or receive benefits from the entities' performance. PGE's financial exposure in these PPAs is limited to capacity and energy payments, which are recovered through the AUT and are subject to the PCAM as detailed in Note 2.

Public utility districts--PGE has long-term PPAs 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 agreements, 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, 2025		PGE's Average Share as of December 31, 2025		Contract Expiration	Total PGE Contract Costs			
			Output	Capacity		2025	2024		
			(in MW)						
Priest Rapids and Wanapum	\$	1,584	8.6%	163	2052	\$	67	\$	75
Wells		200	3.5%	25	2028		10		11

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 2029.

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 through 2025, PGE provided indemnification against the buyer's losses related to a failure to satisfy the PTC and ITC 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, 2025, 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 commencement 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, 2025 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 PPAs that rely on identified plant. Variable payments are generally related to gas storage and PPAs 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):

	2025	2024
Operating lease cost	\$ 26	\$ 2
Finance lease cost:		
Amortization of right-of-use assets	\$ 14	\$ 14
Interest on lease liabilities	14	14
Total finance lease cost	\$ 28	\$ 28

Variable lease cost	\$	22	\$	28
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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,	
		2025	2024
Operating Leases:			
Operating lease right-of-use assets	Net Utility Plant	\$ 303	\$ 312
Current liabilities	Obligations Under Capital Leases - Current	\$ 26	\$ 26
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	277	286
Total operating lease liabilities *		\$ 303	\$ 312
Finance Leases:			
Finance lease right-of-use assets	Net Utility Plant, net	\$ 262	\$ 276
Current liabilities	Obligations Under Capital Leases - Current	\$ 27	\$ 27
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	263	276
Total finance lease liabilities *		\$ 290	\$ 303

* Included in lease liabilities are \$577 million and \$599 million related to purchased power and storage contracts for the years ended December 31, 2025 and 2024, respectively. These agreements include hydro and natural gas generation PPAs, gas storage, and battery storage, all of which are included within the Company's AUT and PCAM regulatory mechanisms.

Lease term and discount rates were as follows:

	December 31, 2025	December 31, 2024
Weighted Average Remaining Lease Term (in years)		
Operating leases	21	22
Finance leases	19	20
Weighted Average Discount Rate		
Operating leases	5.8%	5.8%
Finance leases	4.8%	4.8%

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, 2025, maturities of lease liabilities were as follows (in millions):

	Operating Leases		Finance Leases	
	PPA*	Other	PPA*	Other
2026	\$ 25	\$ 1	\$ 27	\$ --
2027	25	1	27	--
2028	25	1	26	--
2029	25	1	26	--
2030	25	1	26	--
Thereafter	349	39	304	--
Total lease payments	474	44	436	--
Less imputed interest	(187)	(28)	(146)	--
Total	\$ 287	\$ 16	\$ 290	\$ --

* These agreements include hydro and natural gas generation PPAs, gas storage, and battery storage contracts, all of which are included within the Company's AUT and PCAM regulatory mechanisms.

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

	2025	2024
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows used in operating leases	\$ 26	\$ 3
Operating cash flows used in finance leases	14	14
Financing cash flows used in finance leases	14	6
Right-of-use assets obtained in leasing arrangements:		
Operating leases	\$ --	\$ 295

Battery storage agreements--PGE has entered into three battery storage PPAs subsequent to December 31, 2025 that are expected to be accounted for as leases upon commencement. These projects are summarized as follows:

- on January 9, 2026, PGE entered into an agreement with an expected lease commencement date in December 2027 and a term of 20 years, pending OPUC approval of a waiver filing. The expected total fixed contract consideration will approximate \$612 million over the lease term;
- on February 15, 2026, PGE entered into an agreement with an expected lease commencement date in December 2027 and a term of 30 years, subject to approvals. The expected total fixed contract consideration will approximate \$331 million over the lease term; and
- on February 15, 2026, PGE entered into an agreement with an expected lease commencement date in June 2028 and a term of 20 years, pending OPUC approval of a waiver filing. The expected total fixed contract consideration will approximate \$636 million over the lease term.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2025, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation ⁽¹⁾	Construction Work In Progress
Colstrip - Generation	20%	1986	\$ 512	\$ 501	\$ 3
Colstrip-Transmission	Various ⁽²⁾	1986	74	45	1
Pelton/Round Butte	50.01%	1958 / 1964	242	81	10
Total			<u>\$ 828</u>	<u>\$ 627</u>	<u>\$ 14</u>

(1) Excludes AROs and Accumulated Provision for Depreciation, Amortization, and Depletion.

(2) 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 Bonneville Power Administration's transmission system near Townsend, Montana.

Under the respective joint operating agreements for the 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.

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) that began in 1997 of a segment of the Willamette River known as Portland Harbor 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 the 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 were 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 Portland Harbor have improved substantially with the passage of time. 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.

In November 2024, the EPA issued a Special Notice Letter (SNL) to 60 entities, including PGE, with requirements and deadlines that may ultimately lead to litigation, in relation to Portland Harbor. By letter dated May 30, 2025, PGE responded in coordination with other SNL recipients, as recommended by the EPA. Formal negotiations are anticipated to take approximately two years, concluding in fall 2026 and no later than March 2027, according to the EPA.

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 are immaterial.

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, the PHERA allows the Company to defer estimated liabilities and recover prudently 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.

Colstrip-Related Matters

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. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation Agreement and other matters. In 2021, an arbitration process was initiated by co-owner, NorthWestern Corporation, against all other co-owners of Colstrip to address such business disagreements and 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 parties have agreed to stay the arbitration proceedings indefinitely. PGE cannot predict the ultimate outcome of this matter.

Wrongful Death Claims

In September 2025, PGE received a complaint filed in Multnomah County Circuit Court on behalf of the estates of three members of the public and their relatives, with regard to three fatalities that occurred during the January 2024 storm and severe winter weather event. The lawsuit seeks a total of \$375 million related to their deaths and surviving family members' claims. Business entities that own and operate an apartment complex, along with a nearby property owner, are also named as defendants. At this time, as the case is in its early stages, PGE is unable to estimate a range of any reasonably possible loss. The Company denies liability and plans to defend its case.

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 EVENTS

On February 15, 2026, PGE, through a newly formed, wholly owned subsidiary, entered into an Asset Purchase and Service Area Transfer Agreement (the "Agreement") with PacifiCorp, an indirect subsidiary of Berkshire Hathaway Energy Company, to acquire select portions of PacifiCorp's Washington state regulated utility retail business. Under the Agreement, PGE would acquire certain assets and liabilities related to generation, transmission, and distribution business to serve the related service area comprised of approximately 140,000 customers. The stated purchase price is \$1.9 billion in cash, subject to customary adjustments, including adjustments for net working capital, regulatory assets and liabilities, assumed liabilities, and capital expenditures at closing.

The acquisition is supported by a fully committed bridge facility with Barclays Bank PLC and JPMorgan Chase Bank, N.A. for \$1.9 billion. The Company expects to permanently finance the transaction through a balanced mix of debt, equity, and its minority investment partner, Manulife Infrastructure Fund III L.P. and its affiliates including John Hancock Life Insurance Company (USA) ("Manulife"). In connection with the financing plan, PGE expects equity commitments from Manulife to finance up to \$600 million of the purchase. Assuming the closing of the transactions contemplated by the Agreement and the consummation of the financing transactions, Manulife will be the Company's joint venture partner in the business. PGE would remain majority owner and sole operator.

The Agreement also provides for certain termination rights, and under certain specified circumstances, the Company may be required to pay PacifiCorp a termination fee of \$35 million. The transaction is expected to consummate twelve months after submission of regulatory filings, subject to customary closing conditions and regulatory approvals, including under the Hart-Scott-Rodino Act, Section 203 of the Federal Power Act from the FERC, the Washington Utilities and Transportation Commission, the OPUC, the Idaho Public Utilities Commission, the Public Service Commission of Utah, the Public Utilities Commission of the State of California and the Public Service Commission of Wyoming, and certain other federal and state regulatory approvals.

The transaction is expected to be accounted for as a business combination pursuant to ASC 805, Business Combinations, using the acquisition method of accounting and in which PGE would record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent that the consideration transferred is greater than the fair value of the net assets acquired, goodwill will be recorded.

Through December 31, 2025 and the date of filing, fees incurred as a part of the acquisition have been immaterial.

On March 23, 2026, PGE entered into an unsecured Credit Agreement (the "Term Loan Agreement") among the Company, as borrower, the lenders party thereto, U.S. Bank National Association, as administrative agent, and CoBank, ACB and Mizuho Bank Ltd., as co-syndication agents. Under the terms of the Term Loan Agreement, the Company may borrow up to an aggregate of \$350 million in up to four separate borrowings, subject to the

satisfaction or waiver of certain customary conditions. Borrowings made under the Term Loan Agreement may be made through September 23, 2026. The proceeds from the borrowings under the Term Loan Agreement will be used to finance capital expenditures and for general corporate purposes. The Company expects to use a portion of such proceeds to fund capital projects it will acquire pursuant to the Company's 2023 Request for Proposals.

Borrowings under the Term Loan Agreement bear interest, at the Company's option, at a rate equal to either: (i) the Term SOFR Rate (as defined in the Term Loan Agreement) plus 1.10%; or (ii) the Alternate Base Rate (as defined in the Term Loan Agreement) plus 0.10%. In addition, the Company is required to pay each lender under the Term Loan Agreement a commitment fee in respect of any unused commitments under the Term Loan Agreement, which commitment fee accrues from July 22, 2026 to and including the day such commitment terminates, at a percentage rate per annum equal to 0.125%. The maturity date for borrowings under the Term Loan Agreement is March 23, 2028.

The Term Loan Agreement contains customary representations and affirmative and negative covenants (including limitations on total indebtedness exceeding 65% of total capitalization). The Term Loan Agreement also contains events of default customary for credit facilities of this type. The foregoing description of the Term Loan Agreement does not purport to be complete and is qualified in its entirety by reference to the full text of the Term Loan Agreement included as Exhibit 10.1 with the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on March 24, 2026.

On March 23, 2026, the Company entered into an unsecured Credit Agreement (the "Delayed Draw Term Loan Credit Agreement") among the Company, as borrower, the lenders party thereto and J.P.Morgan Chase Bank, N.A., as administrative agent, which provides for a senior unsecured delayed draw term loan in an aggregate principal amount of up to \$681 million (the "Delayed Draw Term Loan"). The Delayed Draw Term Loan is available to be drawn until the earliest of: (i) the date that is five business days after the Outside Date (as defined in the Acquisition Agreement (as defined below) as such date may be extended in accordance with the terms of the Acquisition Agreement); (ii) the closing of the acquisition of the Acquired Business (as defined below) without any borrowing of the Delayed Draw Term Loan; (iii) the date the Company notifies the administrative agent in writing that the Acquisition Agreement is terminated or a public announcement by the Company of its intention not to proceed with the acquisition of the Acquired Business; and (iv) receipt by the administrative agent of written notice from the Company of its election to terminate all commitments under the Delayed Draw Term Loan in full (the earliest of such dates, the "Commitment Termination Date"). Proceeds from the Delayed Draw Term Loan will be used to finance the purchase of certain assets from PacifiCorp, an Oregon corporation (the "Seller"), and transaction costs related to: (i) the electric transmission and distribution business conducted by the Seller serving customers in certain counties in Washington; and (ii) the ownership and operation of certain generation facilities, including related interconnection and other facilities (the "Acquired Business"). The terms of the acquisition of the Acquired Business are set forth in the Asset Purchase and Service Area Transfer Agreement, dated as of February 15, 2026 (the "Acquisition Agreement"), among the Seller, a wholly owned subsidiary of the Company, and the Company, as set forth in Exhibit 2.1 of the Company's Form 8-K filed on February 17, 2026 (the "Prior Form 8-K") and incorporated herein by reference. The Company may assign the Delayed Draw Term Loan to such wholly owned subsidiary subject to the satisfaction of certain conditions. Also, per the terms of the Bridge Facility, as set forth in the Prior Form 8-K, the Delayed Draw Term Loan will reduce the commitment amount of the Bridge Facility by the amount committed under the Delayed Draw Term Loan.

Borrowings under the Delayed Draw Term Loan bear interest, at the Company's option, at a rate equal to either (i) the Term SOFR Rate (as defined in the Delayed Draw Term Loan Credit Agreement), or (ii) the Alternate Base Rate (as defined in the Delayed Draw Term Loan Credit Agreement), in each case, plus an applicable margin determined by reference to the Company's long-term debt securities credit ratings as set forth in the Delayed Draw Term Loan Credit Agreement. In addition, the Company is required to pay each lender under the Delayed Draw Term Loan (a) a commitment fee in respect of any unused commitments under the Delayed Draw Term Loan, which commitment fee accrues from June 15, 2026 to the date such commitment terminates, in an amount determined by reference to the Company's long-term debt securities credit ratings as set forth in the Delayed Draw Term Loan Credit Agreement, and (b) a duration fee equal to 0.10% of the aggregate principal amount of advances outstanding on the date that is 180 days after the funding of the Delayed Draw Term Loan. The maturity date for the Delayed Draw Term Loan is 364 days after the funding thereof.

The Delayed Draw Term Loan Credit Agreement contains customary representations and affirmative and negative covenants (including limitations on total indebtedness exceeding 65% of total capitalization). The Delayed Draw Term Loan Credit Agreement also contains events of default customary for credit facilities of this type. The foregoing description of the Delayed Draw Term Loan does not purport to be complete and is qualified in its entirety by reference to the full text of the Delayed Draw Term Loan Credit Agreement filed herewith as Exhibit 10.2 and incorporated herein by reference.

On March 18, 2026, PGE received the second of two inter-related final orders from the OPUC related to recovery of previously deferred amounts related to its January 2024 storm and damage deferral and 2024 RCE deferrals.

PGE had previously deferred and sought recovery of \$80 million, not including interest, for costs incurred in 2024 under the Company's RCE mechanism, which operates under the PCAM tariff. This mechanism was approved by the OPUC as part of the 2024 GRC proceedings and PGE had requested that the mechanism be extended one year beyond its original sunset date of December 31, 2025. The RCE mechanism allowed PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's AUT, without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. In addition to the RCE, PGE also sought recovery in a separate docket of an additional \$44 million related to storm costs incurred in January 2024 under the OPUC's state of emergency deferral mechanism.

The OPUC's final order in the RCE mechanism docket approved recovery of \$70 million in deferred costs, before consideration of interest, after determining that costs should be shared at a level of 90%, resulting in a reduction to the recovery request. In addition, the OPUC disagreed with PGE's method of estimating the impacts related to wind generating resources in the day ahead forecasts, resulting in a disallowance of \$2 million in previously deferred costs. The OPUC also declined to extend the sunset date for the RCE mechanism.

The OPUC's final order in the storm recovery docket is expected to result in recovery of \$40 million after a disallowance for some operating and maintenance costs of \$1 million and application of an earnings test. The OPUC ordered the application of an earnings test at 20 basis points below the Company's 2024 allowed return on equity of 9.5% on the deferred storm costs of \$44 million. The application of the earnings test is expected to result in a \$3 million reduction of the previously deferred amounts. The following table provides a summary of the filed amounts and ultimate recovery, excluding the effects of previously accrued interest (in millions):

As filed (includes adjustments from initial filings)	
RCE Recovery	\$ 80
Storm Recovery	44
Total Request	124
Adjustments	
Disallowances	3
Application of 90% sharing mechanism	8
Impact of earnings test	3
Total Adjustments	14
Final Orders	\$ 110

As a result of these adjustments and after considering previously accrued interest, PGE expects to record a \$15 million, pre-tax charge to earnings during the first quarter of 2026.

More information about the RCE and Storm cost recovery dockets, UE 457 and UE 458, respectively, is available on the OPUC website at www.oregon.gov/puc.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

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				(4,999,156)	(808)		(4,999,964)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				1,144,015			1,144,015		
3	Preceding Quarter/Year to Date Changes in Fair Value				0			0		
4	Total (lines 2 and 3)	0	0	0	1,144,015	0	0	1,144,015	316,305,169	317,449,184
5	Balance of Account 219 at End of Preceding Quarter/Year	0	0	0	(3,855,141)	(808)	0	(3,855,949)		
6	Balance of Account 219 at Beginning of Current Year	0	0	0	(3,855,141)	(808)	0	(3,855,949)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				63,158			63,158		
8	Current Quarter/Year to Date Changes in Fair Value							0		
9	Total (lines 7 and 8)	0	0	0	63,158	0	0	63,158	307,593,655	307,656,813
10	Balance of Account 219 at End of Current Quarter/Year	0	0	0	(3,791,983)	(808)	0	(3,792,791)		

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Comprised of the net amount of the actuarial valuation of \$1,585,750 of non-qualified benefit plans net of taxes of (\$441,735).

(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Comprised of the net amount of the actuarial valuation of \$86,987 of non-qualified benefit plans net of taxes of (\$23,829).

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

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)	12,946,725,390	12,946,725,390					
4	Property Under Capital Leases	584,407,317	584,407,317					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	2,599,631,465	2,599,631,465					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	16,130,764,172	16,130,764,172					
9	Leased to Others							
10	Held for Future Use	87,938,757	87,938,757					
11	Construction Work in Progress	414,862,438	414,862,438					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	16,633,565,367	16,633,565,367					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	6,556,171,085	6,556,171,085					
15	Net Utility Plant (13 less 14)	10,077,394,282	10,077,394,282					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	6,462,107,626	6,462,107,626					
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	94,063,459	94,063,459					
22	Total in Service (18 thru 21)	6,556,171,085	6,556,171,085					

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

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)
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)	6,556,171,085	6,556,171,085					

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

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					0
3	(302) Franchise and Consents	194,433,114	1,096,226				195,529,340
4	(303) Miscellaneous Intangible Plant	812,298,025				(803,293,471)	9,004,554
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,006,731,139	1,096,226	0	0	(803,293,471)	204,533,894
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	3,328,862					3,328,862
9	(311) Structures and Improvements	116,250,719					116,250,719
10	(312) Boiler Plant Equipment	281,423,892	(1,802,028)	3,170,076			276,451,788
11	(313) Engines and Engine-Driven Generators	0					0
12	(314) Turbogenerator Units	69,576,718	1,909,946	1,304,904			70,181,760
13	(315) Accessory Electric Equipment	25,071,833					25,071,833
13.1	(315.1) Computer Hardware					69,869	69,869
13.2	(315.2) Computer Software						0
13.3	(315.3) Communication Equipment						0
14	(316) Misc. Power Plant Equipment	6,649,907					6,649,907
15	(317) Asset Retirement Costs for Steam Production	28,988,053					28,988,053
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	531,289,984	107,918	4,474,980	0	69,869	526,992,791

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	0					0
19	(321) Structures and Improvements	0					0
20	(322) Reactor Plant Equipment	0					0
21	(323) Turbogenerator Units	0					0
22	(324) Accessory Electric Equipment	0					0
22.1	(324.1) Computer Hardware						0
22.2	(324.2) Computer Software						0
22.3	(324.3) Communication Equipment						0
23	(325) Misc. Power Plant Equipment	0					0
24	(326) Asset Retirement Costs for Nuclear Production	0					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		(324)			4,811,365
28	(331) Structures and Improvements	216,319,752	6,741,927	1,305,302		2,325	221,758,702
29	(332) Reservoirs, Dams, and Waterways	370,250,379	5,591,263	48,055		(999,578)	374,794,009
30	(333) Water Wheels, Turbines, and Generators	109,477,142	20,749,964	(24,354)		(2,325)	130,249,135
31	(334) Accessory Electric Equipment	58,708,403	9,621,118	129,894		(9,399,401)	58,800,226
31.1	(334.1) Computer Hardware					10,464,633	10,464,633
31.2	(334.2) Computer Software						0

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
31.3	(334.3) Communication Equipment		747,207	(616)		5,873,099	6,620,922
32	(335) Misc. Power Plant Equipment	157,080,913	524,057	51,639	(9,952,256)	0	147,601,075
33	(336) Roads, Railroads, and Bridges	17,001,663	114,256	17,460			17,098,459
34	(337) Asset Retirement Costs for Hydraulic Production	5,128					5,128
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	933,654,421	44,089,792	1,527,056	(9,952,256)	5,938,753	972,203,654
35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights						0
35.3	(338.2) Structures and Improvements						0
35.5	(338.4) Solar Panels					1,423,344	1,423,344
35.6	(338.5) Collector System						0
35.7	(338.6) Generator Step-up Transformers (GSU)						0
35.8	(338.7) Inverters						0
35.9	(338.8) Other Accessory Electrical Equipment						0
35.10	(338.9) Computer Hardware						0
35.11	(338.10) Computer Software						0
35.12	(338.11) Communication Equipment					686,070	686,070
35.13	(338.12) Miscellaneous Power Plant Equipment					0	0
35.14	(338.13) Asset Retirement Costs for Solar Production					1,459,436	1,459,436
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)	0	0	0	0	3,568,850	3,568,850
35.16	E. Wind Production Plant						

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
35.17	(338.20) Land and Land Rights						0
35.18	(338.21) Structures and Improvements		33,459,092			208,410,782	241,869,874
35.20	(338.23) Wind Turbines		(110,945,238)	9,717,578		1,324,767,343	1,204,104,527
35.21	(338.24) Wind Towers and Fixtures		60,235,709	556,556		194,294,800	253,973,953
35.23	(338.26) Collector System		81,536,251			38,323,350	119,859,601
35.24	(338.27) Generator Step-up Transformers (GSU)		15,733,042	302,163		14,574,838	30,005,717
35.25	(338.28) Inverters		16,495,425	1,494,678		144,944,763	159,945,510
35.26	(338.29) Other Accessory Electrical Equipment		(70,320,990)			87,692,241	17,371,251
35.27	(338.30) Computer Hardware		4,429,984	911,061		4,819,207	8,338,130
35.28	(338.31) Computer Software						0
35.29	(338.32) Communication Equipment		15,036			6,262,838	6,277,874
35.30	(338.33) Miscellaneous Power Plant Equipment		(21,450,064)			21,450,064	0
35.31	(338.34) Asset Retirement Costs for Wind Production					14,612,245	14,612,245
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)	0	9,188,247	12,982,036	0	2,060,152,471	2,056,358,682
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						0
35.35	(339.2) Structures and Improvements						0
35.36	(339.3) Fuel Holders						0
35.37	(339.4) Boilers						0
35.39	(339.6) Generators						0
35.41	(339.8) Other Accessory Electrical Equipment						0

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
35.42	(339.9) Computer Hardware						0
35.43	(339.10) Computer Software						0
35.44	(339.11) Communication Equipment						0
35.45	(339.12) Miscellaneous Power Plant Equipment						0
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						0
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)	0	0	0	0	0	0
36	G. Other Production Plant						
37	(340) Land and Land Rights	(b) (c) (d) (e) 13,290,818			589,272		13,880,090
38	(341) Structures and Improvements	378,666,917	45,083	119,491		(147,174,588)	231,417,921
39	(342) Fuel Holders, Products, and Accessories	(f) (g) (h) (i) 267,951,720		11,188,539	(5,052,466)		251,710,715
40	(343) Prime Movers	0					0
41	(344) Generators	2,947,659,180	74,007,708	7,510,821		(1,731,841,018)	1,282,315,049
42	(345) Accessory Electric Equipment	252,623,444	13,604,460	104,987		(136,695,922)	129,426,995
42.1	(345.1) Computer Hardware		532			283,625	284,157
42.2	(345.2) Computer Software						0
42.3	(345.3) Communication Equipment		501,168			12,512,917	13,014,085
43	(346) Misc. Power Plant Equipment	68,722,193	269,650			(24,375,082)	44,616,761
44	(347) Asset Retirement Costs for Other Production	30,439,586				(16,071,682)	14,367,904
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,959,353,858	88,428,601	18,923,838	(4,463,194)	(2,043,361,750)	1,981,033,677

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	5,424,298,263	141,814,558	37,907,910	(14,415,450)	26,368,193	5,540,157,654
47	3. Transmission Plant						
48	(350) Land and Land Rights	30,540,568	60,770	20,284		573,840	31,154,894
48.2	(351.1) Computer Hardware		1,051,218			4,818,684	5,869,902
48.3	(351.2) Computer Software					2,304,797	2,304,797
48.4	(351.3) Communication Equipment		72,358	(3,918)		20,276,444	20,352,720
49	(352) Structures and Improvements	36,390,627	28,019,817	88,323		3,429,475	67,751,596
50	(353) Station Equipment	764,830,094	(9,521,416)	6,570,925		70,541,385	819,279,138
51	(354) Towers and Fixtures	53,265,126	(1,051,255)	275,930			51,937,941
52	(355) Poles and Fixtures	206,489,640	100,810,986	553,410		26,470,212	333,217,428
53	(356) Overhead Conductors and Devices	308,360,778	(45,582,530)	108,812		7,623,171	270,292,607
54	(357) Underground Conduit	0					0
55	(358) Underground Conductors and Devices	0					0
56	(359) Roads and Trails	286,332					286,332
57	(359.1) Asset Retirement Costs for Transmission Plant	34,109					34,109
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,400,197,274	73,859,948	7,613,766	0	136,038,008	1,602,481,464
59	4. Distribution Plant						
60	(360) Land and Land Rights	23,041,648	4,558,891	(22,685)		(4,128,975)	23,494,249
61	(361) Structures and Improvements	94,265,009	(8,684,738)	(36,684)		(3,197,654)	82,419,301
62	(362) Station Equipment	875,289,827	73,476,697	3,027,807		(46,140,398)	899,598,319
63.1	(363.1) Computer Hardware		1,298,932			11,774,220	13,073,152

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
63.2	(363.2) Computer Software		1,647,372			70,485,286	72,132,658
63.3	(363.3) Communication Equipment		1,027,002	(4,888)		74,939,063	75,970,953
64	(364) Poles, Towers, and Fixtures	860,576,679	158,683,737	9,367,778		(35,517,547)	974,375,091
65	(365) Overhead Conductors and Devices	961,155,011	77,488,216	1,890,218	(20,295)	(7,556,389)	1,029,176,325
66	(366) Underground Conduit	80,565,348	3,843,151			115,053	84,523,552
67	(367) Underground Conductors and Devices	1,125,189,824	190,951,577	10,689,631		(13,168,360)	1,292,283,410
68	(368) Line Transformers	578,067,921	42,254,414				620,322,335
69	(369) Services	645,811,792	(12,249,277)			14,784	633,577,299
70	(370) Meters	236,567,083	3,719,791	9,291,687			230,995,187
71	(371) Installations on Customer Premises	13,733,953	2,363,767				16,097,720
72	(372) Leased Property on Customer Premises	0					0
73	(373) Street Lighting and Signal Systems	214,586,540	(13,007,922)	1,909,061			199,669,557
74	(374) Asset Retirement Costs for Distribution Plant	476,732					476,732
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,709,327,367	527,371,610	36,111,925	(20,295)	47,619,083	6,248,185,840
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights	0					0
78	(381) Structures and Improvements	0					0
79	(382) Computer Hardware	0					0
80	(383) Computer Software	0					0
81	(384) Communication Equipment	0					0

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
82	(385) Miscellaneous Regional Transmission and Market Operation Plant	0					0
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper	0					0
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	0	0	0	0	0	0
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights		16,380,777			3,600,000	19,980,777
84.3	(387.2) Structures and Improvements		3,142,595			1,290,155	4,432,750
84.4	(387.3) Energy Storage Equipment		265,636,973		(9,537,146)	467,313,848	723,413,675
84.6	(387.5) Collector System		27,222,730			11,142,473	38,365,203
84.7	(387.6) Generator Step-up Transformers (GSU)		27,969,096			11,453,550	39,422,646
84.8	(387.7) Inverters		24,040,852			9,840,177	33,881,029
84.9	(387.8) Computer Hardware		9,309,938			3,818,291	13,128,229
84.10	(387.9) Computer Software					1,369,986	1,369,986
84.11	(387.10) Communication Equipment					571,058	571,058
84.12	(387.11) Miscellaneous Energy Storage Equipment		15,374,038			6,162,404	21,536,442
84.13	(387.12) Asset Retirement Costs for Energy Storage						0
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)	0	389,076,999	0	(9,537,146)	516,561,942	896,101,795
85	7. General Plant						
86	(389) Land and Land Rights	24,150,957	(1,322)			(46,171)	24,103,464
87	(390) Structures and Improvements	347,702,079	6,832,370	(1,230)	(613,164)	(283,520)	353,638,995

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
88	(391) Office Furniture and Equipment	113,750,173	6,453,943	2,378,637		(75,477,844)	42,347,635
89	(392) Transportation Equipment	115,147,291	7,223,350	2,429,423			119,941,218
90	(393) Stores Equipment	4,082,075		221,467		(31,900)	3,828,708
91	(394) Tools, Shop and Garage Equipment	28,248,453	4,667,039	364,813			32,550,679
92	(395) Laboratory Equipment	11,605,492		712,104			10,893,388
93	(396) Power Operated Equipment	41,780,753	5,708,421	288,393			47,200,781
94	(397.1) Computer Hardware		16,124,667	11,133,882		72,928,064	77,918,849
94.1	(397.2) Computer Software		91,078,321	65,666,790		729,133,402	754,544,933
94.2	(397.3) Communication Equipment	295,728,860	8,665,436	75,969		(134,048,833)	170,269,494
95	(398) Miscellaneous Equipment	3,744,557		483		(1,743,981)	2,000,093
96	SUBTOTAL (Enter Total of lines 86 thru 95)	985,940,690	146,752,225	83,270,731	(613,164)	590,429,217	1,639,238,237
97	(399) Other Tangible Property	0					0
98	(399.1) Asset Retirement Costs for General Plant	65,289					65,289
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	986,005,979	146,752,225	83,270,731	(613,164)	590,429,217	1,639,303,526
100	TOTAL (Accounts 101 and 106)	14,526,560,022	1,279,971,566	164,904,332	(24,586,055)	513,722,972	16,130,764,173
101	(102) Electric Plant Purchased (See Instr. 8)	0					0
102	(Less) (102) Electric Plant Sold (See Instr. 8)	0					0
103	(103) Experimental Plant Unclassified	0					0
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	14,526,560,022	1,279,971,566	164,904,332	(24,586,055)	513,722,972	16,130,764,173

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: MiscellaneousPowerPlantEquipmentHydraulicProduction
Includes activities of capitalized lease assets.
(b) Concept: LandAndLandRightsOtherProduction
Includes activities of capitalized lease assets.
(c) Concept: LandAndLandRightsOtherProduction
Includes activities of capitalized lease assets.
(d) Concept: LandAndLandRightsOtherProduction
Includes activities of capitalized lease assets.
(e) Concept: LandAndLandRightsOtherProduction
Includes activities of capitalized lease assets.
(f) Concept: FuelHoldersProducersAndAccessoriesOtherProduction
Includes activities of capitalized lease assets.
(g) Concept: FuelHoldersProducersAndAccessoriesOtherProduction
Includes activities of capitalized lease assets.
(h) Concept: FuelHoldersProducersAndAccessoriesOtherProduction
Includes activities of capitalized lease assets.
(i) Concept: FuelHoldersProducersAndAccessoriesOtherProduction
Includes activities of capitalized lease assets.
(j) Concept: StructuresAndImprovements
Includes activities of capitalized lease assets.
(k) Concept: StructuresAndImprovements
Includes activities of capitalized lease assets.
(l) Concept: StructuresAndImprovements
Includes activities of capitalized lease assets.
(m) Concept: StructuresAndImprovements
Includes activities of capitalized lease assets.
(n) Concept: CommunicationEquipment
Account 397.3-Communication equipment was account 397 - Communication equipment in the 2024 FERC Form 1.
(o) Concept: ElectricPlantInService
The difference between the filed FERC Form 1 ending balance of 2024 and the beginning balance of 2025 is due to FERC deleting accounts 348 - Energy Storage Equipment and 363-Storage battery equipment. The difference of \$513,722,972 is offset in column (f) Transfers.
(p) Concept: ElectricPlantInServiceTransfers

On July 2, 2025, the FERC approved PGEs request under Docket No. EL25-70-000 to reclassify certain 57 kV assets from distribution to transmission. The resulting impact was a transfer of \$84,090,874.

(q) Concept: EnergyStorageEquipmentEnergyStoragePlant

Includes activities of capitalized lease assets.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC PLANT HELD FOR FUTURE USE (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) 01/01/0001	(a) 01/01/0001	543,591
3	Sewell, Washington County, OR	(b) 01/01/0001	(b) 01/01/0001	2,817,507
4	Sewell Easement, Washington County, OR	(c) 01/01/0001	(c) 01/01/0001	332,379
5	Boardman, Morrow County, OR	(d) 01/01/0001	(d) 01/01/0001	832,853
6	Woodburn, Marion County, OR	(e) 01/01/0001	(e) 01/01/0001	20,290,058
7	Sunset, Washington County, OR	(f) 01/01/0001	(f) 01/01/0001	5,895,936
8	Berger/Majestic, Washington County, OR	(g) 01/01/0001	(g) 01/01/0001	13,403,236
9	Ahmad, Washington County, OR	(h) 01/01/0001	(h) 01/01/0001	1,959,257
10	Glee/Madden West and East, Washington County, OR	(i) 01/01/0001	(i) 01/01/0001	5,786,778
11	Harrington, Washington County, OR	(j) 01/01/0001	(j) 01/01/0001	5,107,016
12	Kerr, Washington County, OR	(k) 01/01/0001	(k) 01/01/0001	14,377,405
13	Station E, Multnomah County, OR	(l) 01/01/0001	(aa) 01/01/0001	6,160,681
14	Lambert Neal, Marion County, OR	(m) 01/01/0001	(ab) 01/01/0001	6,118,740
15	Happy Valley, Clackamas County, OR	(n) 01/01/0001	(ac) 01/01/0001	3,992,132
16	Other Land and Land Rights	(o) 01/01/0001	(ad) 01/01/0001	321,188
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				

ELECTRIC PLANT HELD FOR FUTURE USE (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)
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			87,938,757

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2007
(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2008
(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2009
(d) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2020
(e) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2022
(f) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2022
(g) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2023
(h) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2024
(i) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2024
(j) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2024
(k) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2024
(l) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2025
(m) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2025
(n) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
2025
(o) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate
Various
(p) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future

(q) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(r) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(s) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(t) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(u) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(v) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(w) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(x) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(y) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(z) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(aa) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(ab) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(ac) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future
(ad) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Future

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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CONSTRUCTION WORK IN PROGRESS -- ELECTRIC (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Monitor Sub Rebuild (WVRP)	36,219,876
2	Tonquin Substation Build	24,859,428
3	Pearl-Sherwood Upgrades	24,516,348
4	South Milliken 57kV Line Rebuild	24,125,882
5	Transmission LLT Capital Assets	16,767,145
6	Replace or Rewind Failed Transformers	11,899,370
7	T&D Spares and LLT Capital Assets	10,780,556
8	Asset Risk Model Application	10,688,867
9	Oregon City Line Center Project	9,905,671
10	PPMS Project Portfolio Management System	9,375,454
11	Wildfire Mitigation - Underground Willamina	8,992,477
12	Extended Day-Ahead Market (EDAM)	8,858,313
13	Biglow I Wind Enhancement	8,261,068
14	River Mill Rewind Generators Unit 1 and 2	8,054,137
15	Beaver Modernization	7,843,352
16	Harborton Reliability Project	12,172,789
17	Marquam Capacity Addition - Sam Jackson	6,373,781
18	Salem Smart Power Center Repower	6,363,130
19	Substation Communication Upgrade	6,191,026
20	Dynamic Line Ratings	5,797,204
21	Redland Substation Upgrades	5,726,789
22	Round Butte Replace Turbine Shutoff Valves	5,379,325
23	Substation Equipment Replacement	4,696,050
24	Beaver Economizer Upgrade	4,402,282
25	Chemawa Upgrade	4,229,711
26	North Plains Reconductor	4,123,339
27	Blue Lake Distribution Feeders	4,064,474
28	Wheatridge Blade Replacement	3,915,854
29	Waconda Substation Expand	3,583,179
30	Biglow I/II Wind Enhancement	3,364,721

CONSTRUCTION WORK IN PROGRESS -- ELECTRIC (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
31	Warm Springs Power Pathway	3,324,694
32	Pelton Round Butte Construct Fish Facilities	3,303,124
33	Wind Generation Fitness II	3,174,880
34	PGE / DTNA Heavy Duty Charging Station	3,095,600
35	Build Evergreen Phase 4	3,050,915
36	South of Allston Upgrades	2,900,152
37	Beaver Rewind U4 Generator Rotor	2,776,288
38	Facilities Upgrades-EV Readiness	2,728,559
39	Wildfire Mitigation -Undergourd Grand Ronde	2,726,284
40	Distribution System Construct III	2,695,648
41	Malin Reactor Replacement	2,694,615
42	St. Louis Substation Rebuild	2,449,002
43	West Side Hydro Governor Upgrades	2,430,888
44	Wheatridge Demonstration Project	2,428,421
45	Install Diesel Particulate Filters	2,090,468
46	Transmission Tranformer Replacement	2,009,080
47	Molalla Reconductor Project	1,921,455
48	Wildfire Underground Orient	1,833,902
49	Generation Facility Fitness	1,775,592
50	Port Westward II Refurbishment Project	1,770,129
51	Livefront Switch Replacements	1,740,600
52	Next Gen AMI	1,688,733
53	Asset and Resource Management Tool (ARM)	1,663,088
54	Port Westward Relay Upgrades	1,503,331
55	Transmission Circuit Breaker Replacement	1,430,859
56	Transmission Spare Capital Assets	1,425,309
57	Colstrip Haymaker Wind Interconnection	1,326,729
58	Wildfire Mitigation Leland-Carus Project	1,293,827
59	Memorial Substation Build	1,291,436
60	Blue Lake-Glendoveer Reconductor	1,191,212
61	Colstrip Coal Capital Project	1,161,383
62	Sullivan Flow Control Structure Replacement	1,081,331

CONSTRUCTION WORK IN PROGRESS -- ELECTRIC (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
63	Horizon-Keeler Reconductor Project	1,081,119
64	Clackamas Road Improvements	1,075,343
65	Murrayhill-Sherwood Reconductor	1,005,067
66	Energy Supply Lifecycle	997,637
67	Facilities Management Fitness	975,925
68	EV Fleet Partner Phase 2 and 3	958,897
69	Oak Grove Flowline Upgrade	930,745
70	Plexos - Net Variable Power Cost Tool	918,521
71	Wildfire Ignition Prevention Project	829,341
72	Distribution Automation	819,041
73	Next Gen Customer Information System	800,000
74	Customer to Meter - Notifications Phase 2	788,454
75	Carty Controls Upgrade	735,453
76	BPA Substation Upgrades	4,784,985
77	Grassland Substation Expansion	717,566
78	Pelton Round Butte Habitat Fund	700,933
79	Beaver Upgrades	696,808
80	Reedville Substation Rebuild	643,442
81	Wildfire Mitigation - Underground Summit	641,046
82	Prosper Portland Project	619,079
83	Coyote Springs Controls Upgrades	617,628
84	Overhead Distribution Fitness	614,043
85	Biglow Wind SCADA Systems	600,632
86	Minor Projects, <\$1 million, represents 5% of the Total CWIP Balance	22,801,601
43	Total	414,862,438

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

<p>(a) Concept: ConstructionWorkInProgress</p>
<p>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.</p>
<p>(b) Concept: ConstructionWorkInProgress</p>
<p>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.</p>
<p>(c) Concept: ConstructionWorkInProgress</p> <p>PGE has an approximate 15% ownership interest in, and capacity on, the Colstrip transmission facilities. PGE owns 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 Bonneville Power Administrations transmission system near Townsend, Montana.</p>
<p>(d) Concept: ConstructionWorkInProgress</p>
<p>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.</p>
<p>(e) Concept: ConstructionWorkInProgress</p>
<p>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.</p>

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

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	5,573,472,066	5,573,472,066	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	525,171,285	525,171,285		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,431,028	1,431,028		
5	(413) Exp. of Elec. Plt. Leas. to Others	0			
6	Transportation Expenses-Clearing	7,940,437	7,940,437		
7	Other Clearing Accounts	0			
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)	534,542,750	534,542,750	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(164,907,057)	(164,907,057)		
13	Cost of Removal	(16,000,247)	(16,000,247)		
14	Salvage (Credit)	2,500,693	2,500,693		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(178,406,611)	(178,406,611)	0	0
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	FERC 898 Reserve Transfer - Computer Software	532,499,421	532,499,421		
18	Book Cost or Asset Retirement Costs Retired	0			
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,462,107,626	6,462,107,626	0	0
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	538,627,921	538,627,921		

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

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)
21	Nuclear Production	0			
22	Hydraulic Production-Conventional	352,314,747	352,314,747		
23	Hydraulic Production-Pumped Storage	0			
23.1	Solar Production	938,380	938,380		
23.2	Wind Production	715,452,911	715,452,911		
23.3	Other Renewable Production	0			
24	Other Production	699,364,220	699,364,220		
25	Transmission	527,905,576	527,905,576		
26	Distribution	2,828,631,433	2,828,631,433		
27	Regional Transmission and Market Operation	0			
27.1	Energy Storage	28,261,490	28,261,490		
28	General	770,610,948	770,610,948		
29	TOTAL (Enter Total of lines 20 thru 28)	6,462,107,626	6,462,107,626	0	0

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Transfer of accumulated reserve associated with capitalized computer software from account 111 to account 108 in accordance with the requirements of FERC Order 898

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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INVESTMENTS IN SUBSIDIARY COMPANIES (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			9,660,705	1,862,508		11,523,213	
4	Paid in Capital			77,528,661			77,528,661	
5	SubTotal			87,190,366	1,862,508	0	89,052,874	0
6	Salmon Springs Hospitality Group							
7	Common Stock	04/09/1998	05/28/2025	10,000		10,000	0	0
8	Equity in Earnings			(954,682)		(954,682)	0	0
9	SubTotal			(944,682)	0	(944,682)	0	0
42	Total Cost of Account 123.1 \$		Total	86,245,684	1,862,508	(944,682)	89,052,874	0

FOOTNOTE DATA

(a) Concept: EquityInEarningsOfSubsidiaryCompanies

Included in balance is \$25 thousand related to Captive Cell Insurance VIE that will be corrected in fiscal 2026.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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MATERIALS AND SUPPLIES

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)	21,338,923	20,520,498	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	0	0	
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	41,616,304	44,333,303	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	20,353,137	22,813,683	Generation
8	Transmission Plant (Estimated)	564,960	868,942	Transmission
9	Distribution Plant (Estimated)	23,657,898	26,106,032	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,722,087	122,313	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	87,914,386	94,244,273	
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)	4,343,197	4,756,089	
17				
18				
19				
20	TOTAL Materials and Supplies	113,596,506	119,520,860	

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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)

39	Cost of Sales											0	
40	Balance-End of Year	1,202		193		193		193		1,498	0	3,279	0
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: AllowancesInventoryPurchasesTransfersDescription

Prior to the implementation of FERC Order 898, environmental credit inventories were recorded within account 154. The balance reflected herein represents the 12/31/2024 cost value of instruments subsequently reclassified and currently maintained within FERC accounts 158.1, 158.3 and 158.4, as required under the revised regulatory accounting framework.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR	WRITTEN OFF DURING YEAR	Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	^(a) 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)	506,202,250	2,272,472	407	(1,900,000)	161,162,526
49	TOTAL	506,202,250	2,272,472		(1,900,000)	161,162,526

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

\$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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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Transmission Service and Generation Interconnection Study Costs

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	NoHi Cluster	268,668	561.6		
3	LLIR - PAC Dalreed	399	561.6		
4	LGIP 21-100	240	561.6		
5	LGIP 21-101	79	561.6		
6	LGIP 21-204	496	561.6		
7	LGIP 22-109	240	561.6		
8	LGIP 24-242	159	561.6		
9	LLIR 23-113	3,046	561.6		
10	LLIR 24-115	3,503	561.6		
11	LLIR 24-116	1,736	561.6		
12	LLIR Warm Springs Affected Systems	1,256	561.6		
13	LLIR PAC Dual Mesa Affected Systems	463	561.6		
14	SALM Surplus IC	397	561.6		
15	Scout Energy BPA Afs	368	561.6		
16	TSR PTP-103 Invenergy	804	561.6		
17	PLLR - Stimson Lumber	418	561.6		
18	PLLR - Menlo Equities	1,596	561.6		
19	PLLR - Tesla	357	561.6		
20	Transitional Cluster Study Portland	766	561.6		
21	Transitional Cluster Central OR	2,737	561.6		
22	Transitional Cluster Grand Ronde	265	561.6		
23	PLLR - BP Nyberg	1,394	561.6		
24	Marion Co Cluster	129,650	561.6		
25	MN8 Energy	1,555	561.6		
26	Portland Public Schools	775	561.6		
27	PLLR - Walmart EV	1,715	561.6		
28	City of Portland Bureau of Fleet	957	561.6		
29	Siemens	784	561.6		

Transmission Service and Generation Interconnection Study Costs

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
30	IONNA Hayden Island	318	561.6		
31	PLLR - City of Lake Oswego	1,185	561.6		
32	PLLR - Confed. Tribes of Grand Rond	380	561.6		
33	PLLR - Fishtown	6,974	561.6		
34	IONNA West Union	470	561.6		
35	PLLR - Lake Oswego School Dist	424	561.6		
36	PLLR - David Douglas School Dist	323	561.6		
37	IONNA Hart Rd	676	561.6		
38	PLLR Walmart EV - Commercial	72	561.6		
39	PLLR Walmart EV - Turner	212	561.6		
40	PLLR Walmart EV - Sherwood	212	561.6		
41	PLLR Walmart - Happy Valley	144	561.6		
42	PLLR - Verrus Salem	5,422	561.6		
43	Woodburn Cluster	17,392	561.6		
20	Total	459,027		0	
21	Generation Studies				
22	Arcadia	398	561.7		
23	LGIP 21-103	8,150	561.7		
24	LGIP 21-104	30,982	561.7		
25	Cor TX Joint Affected Systems	1,722	561.7		
26	21-22 TSEP Affected System Study	59,610	561.7		
27	LGIP 17-067	2,531	561.7		
28	LGIP - 21-100	48,378	561.7		
29	LGIP 21-101	5,900	561.7		
30	LGIP 21-102	13,309	561.7		
31	LGIP 21-211	2,797	561.7		
32	LGIP 22-109	68,681	561.7		
33	LGIP SALM Surplus	21,515	561.7		
34	LLIR 25-117	4,770	561.7		
35	LLIR 23-113	56,639	561.7		
36	LLIR 24-003	40,155	561.7		
37	LLIR 24-115	96,284	561.7		

Transmission Service and Generation Interconnection Study Costs

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
38	LLIR 24-116	39,657	561.7		
39	LLIR Warm Springs Affected Systems	89,524	561.7		
40	LLIR PAC Dual Mesa Affected Systems	44,090	561.7		
41	Prov Study 17-067	4,418	561.7		
42	TSR PTP-103 Invenergy	35,012	561.7		
43	Lincoln Solar	134	561.7		
44	RI Sundial	327	561.7		
45	SGIP SPQ0280	210	561.7		
46	Transitional Cluster Study Portland	257,336	561.7		
47	Transitional Cluster Central OR	630,440	561.7		
48	Transitional Cluster Grand Ronde	69,523	561.7		
49	2025 All-source RFP	13,928	561.7		
50	NoHi Cluster	2,709	561.7		
51	Transitional Cluster	1,185	561.7		
39	Total	1,650,314		0	
40	Grand Total	2,109,341		0	

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				CREDITS Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Tax Benefits Related to Book/Tax Basis Differences (Amort. period is based on the lives of the properties, approximately 25 years.)	45,100,187	1,190,584	282	10,041,327	36,249,444
2	Previously Flowed to Customers (Amort. period is based on the lives of the properties, approximately 25 years.)	13,515,298	449,915	283	280,991	13,684,222
3	Price Risk Management	184,642,452	602,435,332	547 / 555	606,180,046	180,897,738
4	Deferred Broker Settlement	13,921,573	27,446,649	254 / 547 / 555	41,368,222	0
5	Intervenor Funding - SB 978 (original deferral per OPUC Order No. 03-388 dtd 7/2/2003).	130	8		0	138
6	Intervenor Funding - CUB (original deferral per OPUC Order No. 03-388 dtd 7/2/2003). Amortizing through 12/31/2025.	191,322	5,415	407.3	189,706	7,031
7	Intervenor Funding - Match (original deferral per OPUC Order No. 03-388 dtd 7/2/2003). Amortizing through 12/31/2025.	443,490	277,372	407.3	268,871	451,991
8	Intervenor Funding - Issue (original deferral per OPUC Order No. 03-388 dtd 7/2/2003). Amortizing through 12/31/2025.	497,421	205,520	407.3	470,455	232,486
9	Intervenor Funding - JFA (original deferral per OPUC Order No. 23-033 dtd 2/8/2023). Amortizing through 12/31/2025.	277,921	23,387	407.3	275,574	25,734
10	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	(5,142)	5,142		0	0
11	Glass Insulator Deferral (per OPUC Order No. 10-478 dtd 12/17/2010; UE 215 First Revenue Requirement Stipulation) Amortization period: 56 years	4,973,564	0	571	106,333	4,867,231
12	Pension & Postretirement Funding (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	84,118,197	240,380	228 / 926	20,447,937	63,910,640

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				CREDITS Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
13	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2025.	(1)	11,993,292	143 / 182.3 / 232 / 254 / 407.3 / 431	11,993,291	0
14	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019), Amortizing through 12/31/2025.	0	1,373,288	143 / 182.3 / 232 / 254	1,373,288	0
15	Deferred Cost - FLEX Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2025.	2,100	2,748,280	182.3 / 232 / 254 / 407.3 / 421 / 431	2,750,380	0
16	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2025.	0	4,887,975	182.3 / 232 / 254 / 407.3 / 431	4,887,975	0
17	Gresham Privilege Tax Collection Deferral (Advice No. 17-05, Schedule 134, dtd 02/24/17).	3	0	254	3	0
18	Portland Harbor Environmental Remediation Deferral (Per OPUC Order No. 17-071, Docket No. UM1789, dtd 03/02/17)	37,086,913	5,586,415	143 / 253 / 421	18,482,667	24,190,661
19	Debt Issuance (Interest Rate Hedges for Long Term Debt Amortization period: 30 years beginning April 2019)	3,802,479	0	428.1	157,344	3,645,135
20	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2025.	1	115,930,706	232 / 254 / 431 / 903	114,630,419	1,300,288
21	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017).	0	1,434,726	143 / 182.3 / 232 / 254 / 431	1,434,726	0
22	Community Solar (Per UM-1977, OPUC Order No. 18-477, dtd 12/19/2018), Amortizing through 12/31/2025.	452,886	7,306,928	182.3 / 232 / 254 / 407.3 / 421 / 431	6,530,246	1,229,568
23	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 12/31/2025.	537,924	6,815,432	131 / 143 / 182.3 / 254	6,162,078	1,191,278
24	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020. Amortizing through 12/31/2025.	218,130	284,188	232 / 908	470,480	31,838

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				CREDITS Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
25	Wheatridge Renewable Energy Farm (Per UE-370, Order No. 20-279, dtd 8/26/2020), Amortizing through 12/31/2025.	1,371,874	0	553	52,936	1,318,938
26	Labor Day Wildfire - Emergency Wildfire Deferral (Per UM-2115, Order No. 20-389, dtd 10/27/2020), Amortizing through 12/31/2029.	24,350,730	4,222,036	242 / 407.3 / 571 / 593	9,170,305	19,402,461
27	COVID-19 (Per UM-2064, Order No. 20-376, dtd 10/27/2020), Amortization period 4/1/2023-3/31/2025.	590,999	6,637,955	254 / 421 / 431 / 904	7,228,954	0
28	OPUC Fee Deferral (Per UM-2046, Order No. 20-411, dtd 11/05/2020), Amortizing through 12/31/2025.	595,886	25,889	182.3 / 254 / 407.3	621,775	0
29	February 2021 Ice Storm - Emergency Restoration Costs (Per UM 2156, filing dtd 2/15/2021), Amortizing through 12/31/2029.	58,811,136	9,499,730	242 / 407.3 / 593	21,485,649	46,825,217
30	Independent Evaluator (UM-2184), Amortizing through 12/31/2025.	1,152,724	616,445	143 / 183 / 232 / 407.3	1,603,847	165,322
31	PCAM 2021 (UE-395).	904,411	995,082	555	1,036,444	863,049
32	Wildfire Mitigation Plan (UM-2019), Amortizing through 12/31/2025.	44,284,206	94,787,719	143 / 232 / 407.3 / 421 / 571 / 593	96,949,461	42,122,464
33	Decoupling Deferral - 2022 (UM 1417)	178,463	305,411	421 / 254 / 456	483,874	0
34	Direct Access 2022 (UM 1301).	(2)	2		0	0
35	Lease Obligation Balancing Account	37,156,801	1,708,596		0	38,865,397
36	Colstrip Decommissioning Deferral (UE-394, 5/09/2022).	140,710	106,840	456	74,459	173,091
37	Level III Storm (UE-394), Amortizing through 12/31/2025.	1	4,113,530	229	1	4,113,530
38	CBIAG Deferral (UM 2249) Advice No. 22-36. Amortizing through 12/31/2025.	0	939,186	182.3 / 254	939,186	0
39	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	999,400	4,739,116	182.3 / 553	5,738,516	0
40	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017).	208,882	0	254	208,882	0

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				CREDITS Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
41	Monet NVPC QF Deferral 2023 (UM 1988), Amortizing through 12/31/2025.	648,000	0	555	648,000	0
42	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001).	8,217,465	4,085,336		0	12,302,801
43	Time of Day (TOD) - Deferral 2023 (Per Advice No. 23-40, Special Condition No. 6).	69,136	221	254 / 449.1	69,357	0
44	Time of Day (TOD) - Deferral 2024 (Per Advice No. 23-40, Special Condition No. 6), Amortizing through 12/31/2025.	4,781,004	108,890	182.3 / 449.1	4,686,077	203,817
45	RCE Deferral (Per OPUC Order 23-386 UE-416)	92,159,142	10,155,354	421 / 555	7,916,165	94,398,331
46	January 2024 Ice Storm (Per Advice No. 21-309, UM 2190)	46,977,525	4,855,320	421	1,466,343	50,366,502
47	Direct Access 2024 (Per UM 1301)	762,528	44,098	447	736,081	70,545
48	NEEA Funding (Per UM 2234)	367,693	386,274		0	753,967
49	RVM Deferral (Per OPUC Order 23-386 UE-416)	3,451	3,102,624	421 / 593	3,106,075	0
50	Port Westward 1 Major Maint Deferral (Per OPUC UE 262, Order No. 13-459, dtd 12/9/2013)	2,444,742	5,466,647	182.3 / 553	6,329,136	1,582,253
51	Boardman ARO	(940,402)	75,168	143	181,218	(1,046,452)
52	Asset Retirement Obligations: Balancing Account	8,317,558	12,882,669	254 / 407.3	14,287,369	6,912,858
53	Time of Day (TOD) - Deferral 2025 (Per Advice No. 23-40, Special Condition No. 6).	0	5,778,961		0	5,778,961
54	Direct Access 2025	0	1,010,452		0	1,010,452
55	Transportation Electrification Programs: Electric Avenue (UM 1938), EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Monthly Meter Charge HB-2165 (UM 2218), Amortizing through 12/31/2025.	1	436,045	143 / 182.3 / 232 / 253 / 254 / 431 / 908	436,046	0
56	Colstrip Major Maintenance Deferral (Per OPUC UE-319, Order No. 17-511, dtd 12/18/17)	0	25,021,393	182.3 / 254 / 407.4 / 456 / 506	15,018,975	10,002,418
57	Time of Day (TOD) - Deferral 2026 (Per Advice No. 23-40, Special Condition No. 6).	0	1,282,537	449.1	24,637	1,257,900

OTHER REGULATORY ASSETS (Account 182.3)

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				CREDITS Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
58	TRC Revenue Deferral (OATT Deferral), Amortizing through 12/31/2025.	0	203,976		0	203,976
44	TOTAL	724,330,912	994,234,436		1,049,002,127	669,563,221

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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MISCELLANEOUS DEFERRED DEBITS (Account 186)

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Misc. Undistributed Charges	33,610	786,766	Various	452,078	368,298
2	Net Co-owner / Trust Contribution	745,517	32,702,102	Various	32,041,116	1,406,503
3	Deferred Revolving Credit Agreement Fees (amort through Sept 2030)	2,814,612	617,000	431	594,153	2,837,459
4	Dispatchable Generation (various amort periods from 2017 and extending through 2035)	3,298,593	4,140,480	232 903	5,177,745	2,261,328
5	Utility Property Sales - Selling Expenses	(9,076)	1,770	111	1,770	(9,076)
47	Miscellaneous Work in Progress	2,847,428				4,841,368
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	9,730,684				11,705,880

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Related	303,496,910	314,284,774
3	Regulatory Liabilities	31,278,373	20,542,527
4	Employee Benefits	89,227,549	78,960,883
5	Price Risk Management	60,324,453	58,920,085
6	Tax Credits & NOL's	71,777,637	64,200,238
7	Deferred investment tax credits	22,890,562	73,216,632
7	Other	4,857,424	(b)6,687,494
8	TOTAL Electric (Enter Total of lines 2 thru 7)	583,852,908	616,812,633
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	0	0
17.1	Other (Specify)	6,532,727	(b)6,667,625
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	590,385,635	623,480,258

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

Notes

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

[\(a\)](#) Concept: AccumulatedDeferredIncomeTaxes

Line 7 - Other	2024	2025
Bad Debt Expense	3,253,844	3,453,363
Deferred Revenue	1,101,601	257
Nuclear Decommissioning Trust	10,415,939	8,841,416
Renewable Energy Development	(3,595,729)	(3,469,745)
Finance Lease Liability	(9,507,764)	(8,922,443)
Miscellaneous	3,189,533	6,784,646
Total - Line 7 - Other	<u>4,857,424</u>	<u>6,687,494</u>

[\(b\)](#) Concept: AccumulatedDeferredIncomeTaxes

Line 17 - Other Non-Utility	2024	2025
Property Related	6,782,859	6,582,764
Employee Benefits	(250,133)	84,860
Total - Line 17 - Other Non-Utility	<u>6,532,727</u>	<u>6,667,625</u>

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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CAPITAL STOCKS (Account 201 and 204)

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)
1	Common Stock (Account 201)					
2	Common Stock	160,000,000			115,559,079	2,406,878,394
7	Total	160,000,000			115,559,079	2,406,878,394
8	Preferred Stock (Account 204)					
9	Preferred Stock	30,000,000				
12	Total	30,000,000			0	0

CAPITAL STOCKS (Account 201 and 204)

Line No.	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				
2				
7				
8				
9				
12				

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-13	Year/Period of Report End of: 2025/ Q4
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Other Paid-in Capital

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	0
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	Other Paid in Capital	
18	Beginning Balance Amount	0
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	0
40	Total	18,789,718

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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CAPITAL STOCK EXPENSE (Account 214)

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	44,095,927
22	TOTAL	44,095,927

\$21 million increase in Capital Stock Expense is due to reclassification of expenses incurred between fiscal year 2017 and 2025 from account 201 to account 214. Most of the expenses are underwriting fees and other expenses related to multiple equity forward sale agreements. For further information, refer to Note 12: Equity-Based Plans in the Notes to Financial Statements, p. 122-123.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

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)
1	Bonds (Account 221)						
2	6.875% SERIES VI DUE 8-1-2033	221	50,000,000		519,257	0	437,500
3	6.26% SERIES DUE 5-1-2031	221	100,000,000		723,856	0	0
4	6.31% SERIES DUE 5-1-2036	221	175,000,000		1,270,565	0	0
5	5.80% SERIES DUE 6-1-2039	221	170,000,000		1,460,968	0	0
6	5.81% SERIES DUE 10-1-2037	221	130,000,000		1,109,574	0	517,518
7	\$150mm 5.43% SERIES DUE 5-3-2040	221	150,000,000		1,034,284	0	0
8	\$150mm 4.47% SERIES DUE 6/15/2044	221	150,000,000		1,113,047	0	0
9	\$75mm 4.47% SERIES DUE 8/14/2043	221	75,000,000		558,740	0	0
10	\$50mm 4.84% SERIES DUE 12/15/2048	221	50,000,000		311,154	0	0
11	\$105mm 4.74% SERIES DUE 11/15/2042	221	105,000,000		652,029	0	0
12	\$100mm 4.39% SERIES DUE 8-15-2045	221	100,000,000		645,383	0	0
13	\$100mm 4.44% SERIES DUE 10-15-2046	221	100,000,000		625,030	0	0
14	\$75mm 3.55% SERIES DUE 1/15/2030	221	75,000,000		325,295	0	0
15	\$70mm 3.50% SERIES DUE 5/15/2035	221	70,000,000		305,128	0	0
16	\$150mm 3.98% Series Due 11/21/2047	221	150,000,000		(99,510)	0	0
17	\$75mm 3.98% Series Due 8/3/2048	221	75,000,000		(44,757)	0	0
18	\$75mm 4.47 Series Due 12/11/2048	221	75,000,000		336,938	0	0
19	\$200mm 4.3% Series Due 4-11-2049	221	200,000,000		860,461	0	0
20	\$110mm 3.34%% Series Due 10-15-2049	221	110,000,000		477,767	0	0
21	\$160mm 3.34% Series Due 1-15-2050	221	160,000,000		694,934	0	0

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

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)
22	\$200mm 3.15% Series Due 4-1-2030	221	200,000,000		862,049	0	0
23	\$160mm 1.84% Series Due 12-10-2027	221	160,000,000		645,816	0	0
24	\$70mm 2.32% Series Due 12-10-2032	221	70,000,000		278,000	0	0
25	\$100mm 1.82% Series Due 9-30-2028	221	100,000,000		452,981	0	0
26	\$50mm 2.10% Series Due 9-30-2031	221	50,000,000		226,490	0	0
27	\$100mm 2.20% Series Due 1-15-2034	221	100,000,000		452,981	0	0
28	\$150mm 2.97% Series Due 9-30-2051	221	150,000,000		679,471	0	0
29	\$100mm 5.47% Series Due 11-30-2029	221	100,000,000		438,003	0	0
30	\$100mm 5.56% Series Due 11-30-2033 comm auth 22-031 2/10/2022	221	100,000,000		477,010	0	0
31	\$50m 5.44% Series Due 09-15-2030 comm auth 22-031 2/10/2022	221	50,000,000		202,658	0	0
32	\$150m 5.48% Series Due 9-15-2033 comm auth 22-031 2/10/2022	221	150,000,000		607,974	0	0
33	\$100m 5.68% Series Due 9-15-2038 comm auth 22-031 2/10/2022	221	100,000,000		405,316	0	0
34	\$100m 5.78% Series Due 11-15-2053 comm auth 22-031 2/10/2022	221	100,000,000		145,316	0	0
35	\$100m 5.83% Series Due 11-15-2059 comm auth 22-031 2/10/2022	221	100,000,000		145,316	0	0
36	\$100m 5.15% Series Due 2-22-2029 comm auth 23-450 11/28/2023	221	100,000,000		398,139	0	0
37	\$100m 5.36% Series Due 2-22-2034 comm auth 23-450 11/28/2023	221	100,000,000		398,141	0	0
38	\$250m 5.73% Series Due 2-22-2054 comm auth 23-450 11/28/2023	221	250,000,000		995,530	0	0
39	\$60m 5.36% Series Due 3-25-2035 comm auth 23-450 11/28/23	221	60,000,000		250,973	0	0

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

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)
40	\$50m 5.72% Series Due 3-25-2045 comm auth 23-450 11/28/23	221	50,000,000		209,209	0	0
41	\$200m 5.84% Series Due 3-25-2055 comm auth 23-450 11/28/23	221	200,000,000		836,836	0	0
42	Securitization - debt not issued as of 12/31/2025	221	0		218,525	0	0
43	TransCo Debt Issuance Cost - debt not issued as of 12/31/2025	221	0		2,009,139	0	0
44	\$97.8mm CITY FORSYTH 2.125% DUE 05-01-2033	221	97,800,000		528,702	0	0
45	\$21.0mm CITY FORSYTH 2.375% DUE 05-01-2033	221	21,000,000		97,594	0	0
46	Subtotal		4,678,800,000		24,842,312	0	955,018
47	Reacquired Bonds (Account 222)						
48							
49							
50							
51	Subtotal						
52	Advances from Associated Companies (Account 223)						
53							
54							
55							
56	Subtotal						
57	Other Long Term Debt (Account 224)						
58	^(a) \$300m Term Loan 366 day term variable interest rate comm auth 23-450 11/28/2023.	224	220,000,000		69,350	0	0
59	Subtotal		220,000,000		69,350	0	0
33	TOTAL		4,898,800,000				

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

Line No.	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						
2	08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500
3	05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000
4	05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,500
5	05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,000
6	09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,000
7	11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000
8	06/07/2013	06/15/2044	06/07/2013	06/15/2044	150,000,000	6,705,000
9	08/29/2013	08/14/2043	08/29/2013	08/14/2043	75,000,000	3,352,500
10	12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000
11	11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000
12	08/15/2014	08/15/2045	08/15/2014	08/15/2045	100,000,000	4,390,000
13	10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,453,068
14	01/15/2015	01/15/2030	01/15/2015	01/15/2030	75,000,000	2,662,500
15	05/15/2015	05/15/2035	05/15/2015	05/15/2035	70,000,000	2,450,000
16	11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000
17	08/03/2017	08/03/2048	08/03/2017	08/03/2048	75,000,000	2,985,000
18	12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	3,352,500
19	04/19/2019	04/11/2049	04/19/2019	04/11/2049	200,000,000	8,600,000
20	10/15/2019	10/15/2049	10/15/2019	10/15/2049	110,000,000	3,674,000
21	11/15/2019	01/15/2050	11/15/2019	01/15/2050	160,000,000	5,344,000
22	04/27/2020	04/01/2030	04/27/2020	04/01/2030	200,000,000	6,300,000
23	12/10/2020	12/10/2027	12/10/2020	12/10/2027	160,000,000	2,944,000
24	12/10/2020	12/10/2032	12/10/2020	12/10/2032	70,000,000	1,624,000
25	09/30/2021	09/30/2028	09/30/2021	09/30/2028	100,000,000	1,820,000
26	09/30/2021	09/30/2031	09/30/2021	09/30/2031	50,000,000	1,050,000
27	09/30/2021	01/15/2034	09/30/2021	01/15/2034	100,000,000	2,200,000
28	09/30/2021	09/30/2051	09/30/2021	09/30/2051	150,000,000	4,455,000
29	11/30/2022	11/30/2029	11/30/2022	11/30/2029	100,000,000	5,560,000
30	01/13/2023	01/13/2033	01/13/2023	01/13/2033	100,000,000	5,470,000
31	08/29/2023	09/15/2030	08/29/2023	09/15/2030	50,000,000	2,720,000

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

Line No.	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)
32	08/29/2023	09/15/2033	08/29/2023	09/15/2033	150,000,000	8,220,000
33	09/14/2023	09/15/2038	09/14/2023	09/15/2038	100,000,000	5,680,000
34	11/15/2023	11/15/2053	11/15/2023	11/15/2053	100,000,000	5,780,000
35	11/15/2023	11/15/2059	11/15/2023	11/15/2059	100,000,000	5,830,000
36	02/22/2024	02/22/2029	02/22/2024	02/22/2029	100,000,000	5,150,000
37	02/22/2024	02/22/2034	02/22/2024	02/22/2034	100,000,000	5,360,000
38	02/22/2024	02/22/2054	02/22/2024	02/22/2054	250,000,000	14,325,000
39	03/25/2025	03/25/2035	03/25/2025	03/25/2035	60,000,000	2,465,600
40	03/25/2025	03/25/2045	03/25/2025	03/25/2045	50,000,000	2,192,667
41	03/25/2025	03/25/2055	03/25/2025	03/25/2055	200,000,000	8,954,667
42					0	0
43					0	0
44	03/11/2020	05/01/2033	03/11/2020	05/01/2033	97,800,000	2,078,250
45	03/11/2020	05/01/2033	03/11/2020	05/01/2033	21,000,000	498,750
46					4,678,800,000	208,311,502
47						
48						
49						
50						
51					0	
52						
53						
54						
55						
56					0	
57						
58	11/14/2024	11/17/2025	11/14/2024	11/17/2025	0	4,258,559
59					0	4,258,559
33					4,678,800,000	212,570,061

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

Repaid \$220M outstanding principal amount in 2025; see description column for loan details.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	307,593,655
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	74,134,214
6	Customer Deposits	1,065,633
7	Passthrough Activity	2,990
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Tax Credit Reduction Flowthrough	75,084,036
11	Federal Tax Expense	13,030,315
12	State & Local Tax Expense	39,686,176
13	Regulatory Debits	49,655,378
14	Other	(a)9,519,951
14	Income Recorded on Books Not Included in Return	
15	Regulatory Credits	38,386,020
16	Qualified Nuclear Decommissioning Trust	5,718,552
17	Other	(b)4,936,144
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	453,506,744
21	Employee Benefits	22,586,766
22	State & Local Tax Deduction	10,747,050
23	Property Tax	7,193,353
24	Price Risk Management	3,744,716
25	Other	(c)2,424,055
27	Federal Tax Net Income	20,528,948
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	4,311,079
30	Production Tax Credits	(3,706,859)
31	Return to Provision Federal Tax Adjustment	1,628,881
32	Other Items Affecting Tax	(33,367)

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

Line No.	Particulars (Details) (a)	Amount (b)
33	Total Federal Income Tax - PGE	2,199,734

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Line 9.5 - Other Deductions Recorded on Books Not Deducted for Return

Tax Finance Lease	2,125,843
Political Activity	1,997,637
Renewable Energy Initiatives	1,954,972
Unamortized Loss on Reacquired Debt	863,436
Property Insurance	800,000
Bad Debts	724,635
Meals & Entertainment	466,821
Passthrough Activity	390,489
Miscellaneous	104,924
Other Comprehensive Income	86,987
Fines and Penalties	4,207
Total Other Deductions Recorded on Books Not Deducted for Return	9,519,951

(b) Concept: IncomeRecordedOnBooksNotIncludedInReturn

Line 14.3 - Other Income Recorded on Books Not Included in Return

Key Man Insurance Proceeds	2,996,000
Subsidiary Earnings	1,862,508
Miscellaneous	53,525
Wheatridge Renewable Energy Certificates	24,111
Total Other Income Recorded on Books Not Included in Return	4,936,144

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Line 19.6 - Deductions on Return Not Charged Against Book Income

FERC/SEC Differences	1,213,462
Passthrough Activity	1,184,593
Dividend Received Deduction	26,000
Total Deductions on Return Not Charged Against Book Income	2,424,055

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR	BALANCE AT BEGINNING OF YEAR
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)
1	Income Tax	Federal Tax	Federal	2025	0	2,168,694
2	FERC Resale/Coord	Federal Tax	Federal	2025	1,532,540	0
3	Foreign Insurance Excise Tax	Federal Tax	Federal	2025	0	0
4	FICA (Employer Share)	Federal Tax	Federal	2025	1,652,313	0
5	Unemployment	Federal Tax	Federal	2025	(101,211)	0
6	Power License	Federal Tax	Federal	2025	(1,412,794)	(40,310)
7	Subtotal Federal Tax				1,670,848	2,128,384
8	Income Tax	Income Tax	Montana	2025	0	(261,461)
9	County & City Income Tax	Income Tax	Oregon	2025	0	2,713,030
10	Subtotal Income Tax				0	2,451,569
11	Corp Excise Tax and CAT	Excise Tax	Oregon	2025	0	5,223,008
12	Subtotal Excise Tax				0	5,223,008
13	Corporate Franchise Tax	Franchise Tax	California	2025	0	(1,464,702)
14	City Taxes & Licenses	Franchise Tax	Oregon	2025	9,568,449	0
15	Subtotal Franchise Tax				9,568,449	(1,464,702)
16	Unemployment	Payroll Tax	Oregon	2025	2,160,217	0
17	Transportation Tax	Payroll Tax	Oregon	2025	556,382	0
18	Workers Comp Assessment	Payroll Tax	Oregon	2025	(78,888)	0
19	Subtotal Payroll Tax				2,637,711	0
20	Other State Income Tax	State Tax	Various	2025	0	8,450
21	Subtotal State Tax				0	8,450
22	Department of Energy	Other Taxes and Fees	Oregon	2025	0	946,928
23	Public Utility Comm Fees	Other Taxes and Fees	Oregon	2025	0	0
24	Department of Enviro Quality	Other Taxes and Fees	Oregon	2025	169,708	0
25	Water Power Fee	Other Taxes and Fees	Oregon	2025	0	(198,562)

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR	BALANCE AT BEGINNING OF YEAR
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)
26	Goods & Services Tax	Other Taxes and Fees	Canada	2025	(162)	0
27	Subtotal Other Taxes and Fees				169,546	748,366
28	Property Taxes	Property Tax	Washington	2025	1,715,267	0
29	Property Taxes	Property Tax	Montana	2025	3,193,696	0
30	Property Taxes	Property Tax	Oregon	2025	0	46,072,910
31	Subtotal Property Tax				4,908,963	46,072,910
32	Electric Energy Producers Tax	Other License And Fees Tax	Montana	2025	242,274	0
33	Subtotal Other License And Fees Tax				242,274	0
40	TOTAL				19,197,791	55,167,985

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (l)
				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	
1	2,200,065	2,927,865	0	0	2,896,494	6,460,350
2	1,221,296	413,807	0	2,340,029	0	0
3	0	0	0	0	0	172,234
4	35,828,268	35,479,661	0	2,000,920	0	12,307,961
5	138,868	143,391	0	(105,734)	0	52,012
6	6,302,177	6,445,368	0	(1,676,715)	(161,040)	0
7	45,690,674	45,410,092	0	2,558,500	2,735,454	18,992,557
8	79,211	100,000	0	0	(240,672)	115,734
9	354,794	131,131	0	0	2,489,367	443,152
10	434,005	231,131	0	0	2,248,695	558,886
11	12,704,699	11,884,028	0	0	4,402,337	14,283,217
12	12,704,699	11,884,028	0	0	4,402,337	14,283,217
13	825,017	607,684	0	0	(1,682,035)	908,960
14	69,947,253	74,475,279	0	5,040,423	0	69,947,253
15	70,772,270	75,082,963	0	5,040,423	(1,682,035)	70,856,213
16	5,156,260	4,293,416	0	3,023,061	0	1,748,748
17	2,788,407	2,640,552	0	704,237	0	1,115,587
18	68,573	307,946	0	(318,261)	0	25,668
19	8,013,240	7,241,914	0	3,409,037	0	2,890,003
20	593	3,366	(259)	0	11,482	490
21	593	3,366	(259)	0	11,482	490
22	2,521,385	3,255,070	(5)	0	1,680,618	2,243,391
23	15,573,216	15,573,216	0	0	0	0
24	684,232	823,930	0	30,010	0	0
25	682,231	569,101	0	0	(311,692)	0
26	0	0	0	(162)	0	0
27	19,461,064	20,221,317	(5)	29,848	1,368,926	2,243,391
28	1,679,332	1,762,148	0	1,632,451	0	1,679,332
29	6,612,527	6,499,959	65,060	3,371,324	0	4,872,343
30	97,876,736	103,625,954	0	157,512	51,979,640	93,212,375
31	106,168,595	111,888,061	65,060	5,161,287	51,979,640	99,764,050

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (l)
				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	
32	960,160	962,932	0	239,502	0	560,673
33	960,160	962,932	0	239,502	0	560,673
40	264,205,300	272,925,804	64,796	16,438,597	61,064,499	210,149,480

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

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	DISTRIBUTION OF TAXES CHARGED	DISTRIBUTION OF TAXES CHARGED	DISTRIBUTION OF TAXES CHARGED
	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	0	0	(4,260,285)
2	0	0	1,221,296
3	0	0	(172,234)
4	0	0	23,520,307
5	0	0	86,856
6	0	0	6,302,177
7	0	0	26,698,117
8	0	0	(36,523)
9	0	0	(88,358)
10	0	0	(124,881)
11	0	0	(1,578,518)
12	0	0	(1,578,518)
13	0	0	(83,943)
14	0	0	0
15	0	0	(83,943)
16	0	0	3,407,512
17	0	0	1,672,820
18	0	0	42,905
19	0	0	5,123,237
20	0	0	103
21	0	0	103
22	0	0	277,994
23	0	0	15,573,216
24	0	0	684,232
25	0	0	682,231
26	0	0	0
27	0	0	17,217,673
28	0	0	0
29	0	0	1,740,184
30	0	0	4,664,361
31	0	0	6,404,545
32	0	0	399,487

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

Line No.	DISTRIBUTION OF TAXES CHARGED		DISTRIBUTION OF TAXES CHARGED		DISTRIBUTION OF TAXES CHARGED	
	Extraordinary Items (Account 409.3)		Adjustment to Ret. Earnings (Account 439)		Other	
	(m)		(n)		(o)	
33		0		0		399,487
40				0		54,055,820

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year	Deferred for Year	Allocations to Current Year's Income	Allocations to Current Year's Income
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)
1	Electric Utility					
2	Electric Utility - not subject to tax normalization	60,295,123	411.4	140,881,361	411.4	7,554,269
3	Electric Utility - subject to tax normalization	376,195	410	70,858	420	8,957
8	TOTAL Electric (Enter Total of lines 2 thru 7)	60,671,318		140,952,219		7,563,226
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)					
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year	Deferred for Year	Allocations to Current Year's Income	Allocations to Current Year's Income
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
47	OTHER TOTAL					
48	GRAND TOTAL	60,671,318				

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Line No.	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
1				
2	0	193,622,215	16.26	
3	0	438,096	42.00	
8	0	194,060,311		
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Line No.	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
47				
48		194,060,311		

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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OTHER DEFERRED CREDITS (Account 253)

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Tenant security deposits	160,000	418	160,000		0
2	Deferred Liability for Transferred Non-Qualified Plan Benefits	461,209	421	461,209		0
3	Reserve for Environmental Remediation Costs	4,000,000	185	4,000,000		0
4	Clean Fuels Program OPUC 17-250 and 17-512	20,648,074	107 154 184 186 232 253 254 908 921	13,514,264	30,335,311	37,469,121
5	Wireless Mods & Make Ready Clearing	1,699,731			952,505	2,652,236
6	Equity Forward Transaction Credit	(23,455)	232	49,709		(73,164)
7	AED: Grant Implementation	135,000			220,000	355,000
8	Miscellaneous Deferred Revenue		131 232	859,176		(859,176)
47	TOTAL	27,080,559		19,044,358	31,507,816	39,544,017

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR		CHANGES DURING YEAR		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)		
1	Account 282							
2	Electric	944,427,755	161,036,607	78,821,936				
3	Gas	0						
4	Other (Specify)	0						
5	Total (Total of lines 2 thru 4)	944,427,755	161,036,607	78,821,936	0		0	
6								
7								
8								
9	TOTAL Account 282 (Total of Lines 5 thru 8)	944,427,755	161,036,607	78,821,936	0		0	
10	Classification of TOTAL							
11	Federal Income Tax	745,913,308	110,912,536	55,972,655				
12	State Income Tax	195,773,341	49,938,165	22,775,123				
13	Local Income Tax	2,741,106	185,906	74,158				

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

Line No.	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)
1					
2	182.3	40,346,600	254	40,792,420	1,027,088,246
3					0
4					0
5		40,346,600		40,792,420	1,027,088,246
6					0
7					0
8					0
9		40,346,600		40,792,420	1,027,088,246
10					
11	182.3	34,244,686	254	34,274,623	800,883,126
12	182.3	4,074,052	254	4,327,914	223,190,245
13	182.3	2,027,862	254	2,189,883	3,014,875

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR			CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	
1	Account 283					
2	Electric					
3	Property Related	12,201,219				
4	Price Risk Management	45,020,992	24,901,052	25,914,024		
5	Regulatory Assets	120,522,796	80,740,009	98,397,686		
6	Regulatory Liabilities	2,556,555				
7	Other	17,590,556	1,943,813	483,317		
9	TOTAL Electric (Total of lines 3 thru 8)	197,892,118	107,584,874	124,795,027	0	0
10	Gas					
11						
12						
13						
14						
15						
16						
17	TOTAL Gas (Total of lines 11 thru 16)					
18	TOTAL Other	14,238,604			11,294,590	5,390,171
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	212,130,722	107,584,874	124,795,027	11,294,590	5,390,171
20	Classification of TOTAL					
21	Federal Income Tax	148,558,486	76,841,446	89,133,630	8,067,200	3,849,531
22	State Income Tax	57,878,933	30,647,956	35,550,652	3,217,368	1,535,826
23	Local Income Tax	5,693,303	95,472	110,745	10,022	4,814

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

Line No.	ADJUSTMENTS	ADJUSTMENTS	ADJUSTMENTS	ADJUSTMENTS	Balance at End of Year (k)
	Debits	Debits	Credits	Credits	
	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1					
2					
3	254	15,613,239	182.3	15,640,828	12,228,808
4	254	506,889	182.3	487,724	43,988,855
5	254	2,431,420	182.3	3,039,289	103,472,988
6	254	2,556,555			0
7	254	621,962	182.3	843,967	19,273,057
9		21,730,065		20,011,808	178,963,708
10					
11					
12					
13					
14					
15					
16					
17					0
18	254	76,587	182.3	138,157	20,204,593
19		21,806,652		20,149,965	199,168,301
20					
21	254	14,558,067	182.3	12,967,050	138,892,954
22	254	3,924,621	182.3	3,934,033	54,667,191
23	254	3,323,964	182.3	3,248,882	5,608,156

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

01

Regulatory Assets:	Beginning Balance	Ending Balance
ASC 715 Pension & Post Retirement	23,167,408	17,603,541
ASC 980 Mark-to-Market	19,156,256	14,931,230
Miscellaneous	3,515,429	4,426,358
Decoupling	(38,979)	(92,221)
Direct Access Deferral	(17,542,052)	(34,634,910)
Schedule 18	17,471,967	34,871,798
Community Solar	55,598	257,949
Time of Day (TOD)	1,677,009	2,386,041
Feed in Tariff (FIT)	116,786	296,678
Portland Harbor (PHERA)	8,869,919	5,562,129
Covid-19	(399,494)	(557,513)
Wildfire	13,916,515	10,889,404
Storm Deferral	24,127,155	21,140,102
PCAM Deferral	23,635,748	22,585,933
PTC Transfer	2,793,531	3,806,469
Subtotal Regulatory Assets	120,522,796	103,472,988

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Utility):	Beginning Balance	Ending Balance
Prepaid Property Tax	11,899,430	13,625,292
Unamortized Loss on Reacquired Debt	4,127,470	3,889,735
Local Flow-Through Deferred Income Tax	1,563,656	1,758,030
Subtotal Other (Utility)	17,590,556	19,273,057

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Non-Utility):	Beginning Balance	Ending Balance
Other	(11,799)	(132,218)
PCAM Deferral	1,989,000	3,643,956
Community Solar	69,169	80,667
Time of Day (TOD)	44,043	124,940
Portland Harbor (PHERA)	1,452,965	1,810,786
Wildfire	4,984,922	6,053,854
Covid-19	504,274	504,274
Storm Deferral	5,004,897	6,757,505
Feed in Tariff (FIT)	31,330	31,330
Decoupling	91,843	92,502
EIP	96,681	1,233,029
TOLI	(18,721)	3,968
Subtotal Other (Non-Utility)	14,238,604	20,204,593

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OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Excess Deferred Income Taxes	237,348,669	190	15,709,861	56,105,600	277,744,408
2	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001).	0	421	4,763	4,763	0
3	Asset Retirement Obligations: Balancing Account	1	407.3	425,186	425,185	0
4	Boardman ARO	1	407.3	6,349	6,348	0
5	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	0	254 / 456 / 553	1,632,573	1,898,045	265,472
6	Colstrip Major Maintenance Deferral (Per OPUC UE-319, Order No. 17-511, dtd 12/18/17)	2,014,155	254 / 407.4 / 456	6,465,184	4,451,029	0
7	Port Westward 2 Major Maintenance Deferral (Per OPUC 2015 GRC Docket UE-283, OPUC Order No.14-422, dtd 12/4/2014)	2,823,693	254 / 456	2,111,132	1,036,668	1,749,229
8	Zero Interest Program Loan Repayments (Per Advice No. 05-19 dtd 12/20/2005)	190,696		0	52,474	243,170
9	Energy Efficiency - Balancing Account (Per Advice No. 07-25 dtd 5/20/2008). Amortizing through 12/31/2025.	1,350,853	407.4	1,292,601	39,391	97,643
10	Sunway 3 Investment Deferral (Per UM 1480 dtd 4/01/2010; Amortization over 20 years commencing 2010)	250,030	407.4	45,480	0	204,550
11	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017).	(15,250)	421	1,932	17,182	0
12	PRC Acquisition (Per OPUC UE-283 Final GRC Order No.14-422, dtd 12/04/2014, Second Partial Stipulation dtd 9/2/2014)	250,670	254	250,670	0	0
13	Deferred Broker Settlement	0	182.3 / 235	15,926,825	21,843,159	5,916,334
14	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order 10-198 dtd 5/28/2010 reauthorized OPUC Order 15-185 dtd 6/09/2015), Amortizing through 12/31/2025.	0	182.3 / 254 / 421	4,934,009	4,934,009	0
15	Research & Development Tax Credits (Per UM-1991, OPUC Order No. 18-464 dtd 12/14/2018), Amortizing through 12/31/2025.	2,071,731	190 / 407.4 / 411.1 / 923	2,038,471	1,212,716	1,245,976

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
16	Postretirement Plans (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	2,027,576	219	104,988	2,696,657	4,619,245
17	OCAT (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020).	370,953	254 / 407.4	372,804	1,851	0
18	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019), Amortizing through 12/31/2025	961,010	182.3 / 254	968,202	743,060	735,868
19	Deferred Cost - FLEX Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2025.	1,064,931	182.3 / 254	343,020	438,692	1,160,603
20	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2025.	1,289,201	182.3 / 254	775,992	1,491,233	2,004,442
21	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2025.	1,493,798	182.3 / 254	1,672,736	1,002,257	823,319
22	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017).	1,234,430	182.3 / 254	1,907,722	1,197,739	524,447
23	Wheatridge RECs (UE 391), Amortizing through 12/31/2025.	5,943,481	555	5,536,263	203,960	611,178
24	Monet NVPC QF Deferral 2022 (UM 1988).	2,472	254	2,472	0	0
25	Regional Power Act (RPA)	33,408		0	67,469	100,877
26	Direct Access 2023 (Per UM-1301).	402,242	254 / 447	404,495	2,253	0
27	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	294,643		0	545,706	840,349
28	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2025.	3,664,588	182.3	3,664,588	0	0
29	KB Pipeline MMA (UE-394, 5/09/2022, amortization of 5 years)	46,647	254 / 456	241	9,484	55,890
30	CBIAG Deferral (UM 2249) Advice No. 22-36. Amortizing through 12/31/2025.	230,714	182.3	294,842	233,658	169,530
31	Coyote Springs Major Maintenance Accrual LTSA (per OPUC GRC 95-1216, dtd 11/20/1995)	273,061	254 / 456	1,578,887	1,876,956	571,130

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
32	Clearwater Deferral (Per Advicee No. 23-20, UE-427) Renewable Resource Automatic Adjustment Clause (RAAC).	39,546,030	431 / 449.1	59,561,926	42,209,562	22,193,666
33	RVM Deferral (Per OPUC Order 23-386 UE-416)	0		0	472,134	472,134
34	Community Solar (Per UM-1977, OPUC Order No. 18-477, dtd 12/19/2018), Amortizing through 12/31/2025.	0	182.3	120,016	120,016	0
35	COVID-19 (Per UM-2064, Order No. 20-376, dtd 10/27/2020), Amortizing through 3/31/2025.	0	182.3 / 904	3,512,773	3,512,773	0
36	Transportation Electrification Programs: Electric Avenue (UM 1938), EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Monthly Meter Charge HB-2165 (UM 2218), Amortizing through 12/31/2025.	15,760,244	107 / 143 / 182.3 / 232 / 253 / 254 / 415 / 903 / 908 / 921	18,257,461	19,243,674	16,746,457
37	Schedule 109 Deferral (Per Advice Filing No. 25-28)	0	143 / 232	12,637,702	25,650,836	13,013,134
38	OPUC Fee Deferral (Per UM-2046, Order No. 20-411, dtd 11/05/2020), Amortizing through 12/31/2025.	0		0	11,844	11,844
41	TOTAL	320,924,678		162,562,166	193,758,383	352,120,895

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Electric Operating Revenues							
Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,427,684,968	1,406,370,635	7,596,298	7,731,594	840,457	829,721
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	966,187,754	904,898,637	6,425,897	6,466,018	114,676	113,724
5	Large (or Ind.) (See Instr. 4)	560,496,980	457,455,750	5,904,529	5,032,385	285	281
6	(444) Public Street and Highway Lighting	14,976,918	14,304,206	41,443	42,625	236	218
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,969,346,620	2,783,029,228	19,968,167	19,272,622	955,654	943,944
11	(447) Sales for Resale	406,261,710	588,094,149	9,856,351	10,305,039	40	41
12	TOTAL Sales of Electricity	3,375,608,330	3,371,123,377	29,824,518	29,577,661	955,694	943,985
13	(Less) (449.1) Provision for Rate Refunds	(20,225,849)	36,929,618				
14	TOTAL Revenues Before Prov. for Refunds	3,395,834,179	3,334,193,759	29,824,518	29,577,661	955,694	943,985
15	Other Operating Revenues						
16	(450) Forfeited Discounts	9,283,047	7,772,424				
17	(451) Miscellaneous Service Revenues	1,348,315	1,432,181				
18	(453) Sales of Water and Water Power	(19,913)	(33,602)				
19	(454) Rent from Electric Property	25,104,093	19,666,388				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	92,042,249	73,639,396				

Electric Operating Revenues							
Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
22	(456.1) Revenues from Transmission of Electricity of Others	24,592,275	24,044,195				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	152,350,066	126,520,982				
27	TOTAL Electric Operating Revenues	3,548,184,245	3,460,714,741				
Line 12, column (b) includes \$ 2,353,000 of unbilled revenues.							
Line 12, column (d) includes (82,708) MWH relating to unbilled revenues							

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes \$16,176,576 in revenue related to the delivery of 547,991 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 2025, 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 \$25,000,994 in revenue related to the delivery of 2,013,501 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2025, 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:		Q4-2025
Boardman Decomm Balance Account		8,702,916
Bradley Solar 2		184,484
Cluster Study		1,450,000
Colstrip Major Maint. Deferral		2,014,155
Coyote Springs Major Maint. Deferral		(563,543)
EV Charging		642,534
Gain(Loss) on Gas Resale		149,380
Hydro License Implementation and Compliance		1,228,519
OHSU Revenue		160,000
Other		4,709,180
PW2 Major Maint. Deferral		1,074,464
QF Study Application Fee		305,739
RPA Balancing		61,169,502
Steam Sales		2,363,938
Time of Day Deferral		5,863,683
Transmission Resale		2,587,299
Grand Total		92,042,249

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes \$9,557,608 in revenue related to the delivery of 514,842 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 2024, 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 \$22,389,721 in revenue related to the delivery of 1,909,068 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2024, 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:	2024
Boardman Decomm Balance Account	7,746,924
Boardman Severance	8,692
Colstrip Decommissioning	56,359
Colstrip Major Maint. Deferral	3,252,940
Coyote Springs Major Maint. Deferral	(129,056)
Firm PTP prepayment	113,259
Gain(Loss) on Gas Resale	(485,179)
Hydro License Implementation and Compliance	1,169,088
Lost Revenue Recovery	(1,844,561)
Other	2,938,975
PW1 Major Maint. Deferral	2,752,945
PW2 Major Maint. Deferral	1,388,603
RPA Balancing	53,484,293
Sch. 32 Sales Norm Adj	(3,281,523)
Sch. 7 Sales Norm Adj	(1,072,000)
Sch. 83 Sales Norm Adj	(825,459)
Steam Sales	3,022,478
Time of Day Deferral	4,342,273
Transmission Resale	1,000,345
Grand Total	73,639,396

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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	7,584,795	1,422,468,309	836,258	9,069.9222	0.1875
2	15-Outdoor Area Lighting	1,458	868,659	4,199	347.2255	0.5958
41	TOTAL Billed Residential Sales	7,586,253	1,423,336,968	840,457	9,026.3428	0.1876
42	TOTAL Unbilled Rev. (See Instr. 6)	10,045	4,348,000			0.4329
43	TOTAL	7,596,298	1,427,684,968	840,457	9,038.2946	0.1879

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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	9,853	3,213,711	8,012	1,229.7803	0.3262
2	32-Small Nonresidential	1,514,222	280,940,753	89,173	16,980.7229	0.1855
3	38-Large Nonresidential	36,809	7,073,582	402	91,564.6766	0.1922
4	47-Small Irrigation & Drainage	20,531	5,476,254	2,782	7,379.9425	0.2667
5	49-Large Irrigation & Drainage	61,719	14,337,238	1,271	48,559.402	0.2323
6	83-Large Nonresidential	2,737,998	388,755,830	11,200	244,464.1071	0.142
7	85-Large Nonresidential	2,029,482	246,154,192	1,194	1,699,733.6683	0.1213
8	485-Large Nonresidential COS O	23,208	1,864,214	12	1,934,000	0.0803
9	485-Large Nonresidential COS O	0	8,923,565	198	0	
10	489-Large Nonresidential COS O	0	374,708	1	0	
11	532-Small Nonresidential DAS	0	758,571	256	0	
12	538-Large Nonresidential Opt.	0	1,374	2	0	
13	583-Large Nonresidential DAS	0	2,723,952	137	0	
14	585-Large Nonresidential DAS	0	3,109,810	36	0	
41	TOTAL Billed Small or Commercial	6,433,822	963,707,754	114,676	56,104.3462	0.1498
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(7,925)	2,480,000			(0.3129)
43	TOTAL Small or Commercial	6,425,897	^(a) 966,187,754	114,676	56,035.2384	0.1504

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes \$16,176,576 in revenue related to the delivery of 547,991 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 2025, 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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	89-Large Nonresidential	40,814	4,516,058	3	13,604,666.6667	0.1106
2	489-Large Nonresidential COS O	0	1,450,413	2	0	
3	85-Large Nonresidential	640,994	71,159,245	183	3,502,699.4536	0.111
4	89-Large Nonresidential	1,553,118	144,608,059	22	70,596,272.7273	0.0931
5	90-Large Nonresidential	3,673,323	314,024,199	7	524,760,428.5714	0.0855
6	485-Large Nonresidential COS O	33,749	2,260,301	2	16,874,500	0.067
7	489-Large Nonresidential COS O	7,887	531,129	1	7,887,000	0.0673
8	689-Large Nonresidential	39,472	3,031,899	1	39,472,000	0.0768
9	485-Large Nonresidential COS O	0	5,037,595	46	0	
10	489-Large Nonresidential COS O	0	9,924,810	14	0	
11	585-Large Nonresidential DAS	0	24,448	1	0	
12	689-Large Nonresidential	0	8,403,824	3	0	
41	TOTAL Billed Large (or Ind.) Sales	5,989,357	564,971,980	285	21,015,287.7193	0.0943
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(84,828)	(4,475,000)			0.0528
43	TOTAL Large (or Ind.)	5,904,529	^(a) 560,496,980	285	20,717,645.614	0.0949

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes \$25,000,994 in revenue related to the delivery of 2,013,501 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2025, 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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	8,049	4,774,327	218	36,922.0183	0.5932
2	92-Traffic Signals	2,816	295,944	16	176,000	0.1051
3	95-Street & Hwy Lighting (New	30,578	9,906,647	2	15,289,000	0.324
41	TOTAL Billed Public Street and Highway Lighting	41,443	14,976,918	236	175,605.9322	0.3614
42	TOTAL Unbilled Rev. (See Instr. 6)	0	0			
43	TOTAL	41,443	14,976,918	236	175,605.9322	0.3614

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
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41	TOTAL Billed Other Sales to Public Authorities					
42	TOTAL Unbilled Rev. (See Instr. 6)	0	0			
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
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39						
40						
41	TOTAL Billed Sales To Railroads and Railways					
42	TOTAL Unbilled Rev. (See Instr. 6)	0	0			
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
32						
33						
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41	TOTAL Billed Interdepartmental Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)	0	0			
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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SALES OF ELECTRICITY BY RATE SCHEDULES

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)
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)	0	(20,225,849)			
43	TOTAL		(20,225,849)			

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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	20,050,875	2,966,993,620	955,654	20,981.3123	0.148
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(82,708)	2,353,000			(0.0284)
43	TOTAL - All Accounts	19,968,167	2,969,346,620	955,654	20,894.7663	0.1487

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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SALES FOR RESALE (Account 447)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Alberta Electric System Operator (AESO)	SF	AESO			
2	Altop Energy Trading LLC	SF	WSPP-1			
3	J Aron & Company	SF	EEI			
4	Arizona Public Service Co.	SF	WSPP-1			
5	Avangrid Renewables (was Iberdrola)	SF	EEI			
6	Atlas Energy, LLC	SF	EEI			
7	Avista Corp.	SF	WSPP-1			
8	BP Energy Company	SF	PGE-11			
9	Black Hills Power, Inc.	SF	WSPP-1			
10	Bonneville Power Administration	SF	WSPP-1			
11	British Columbia Hydro & Power Authority	SF	WSPP-1			
12	Brookfield Energy Marketing LP	SF	WSPP-1			
13	California Independent System Operator	SF	CAISO			
14	Calpine Energy Services, L.P.	SF	EEI			
15	Chelan County, PUD No. 1, Washington	SF	WSPP-1			
16	Citigroup Energy Inc.	SF	WSPP-1			
17	Citadel Energy Marketing LLC	SF	WSPP-1			
18	City of Glendale	SF	WSPP-1			
19	Clatskanie Peoples Utility District	SF	WSPP-1			
20	ConocoPhillips Company	SF	WSPP-1			
21	CP Energy Marketing (US) Inc	SF	WSPP-1			
22	Douglas County, PUD No. 1, Washington	LU	WSPP-1			
23	Dynasty Power	SF	WSPP-1			
24	EDF Trading North America, LLC	SF	WSPP-1			
25	Energy Keepers, Inc.	SF	WSPP-1			
26	ENMAX Energy Marketing Inc.	SF	EEI			

SALES FOR RESALE (Account 447)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
27	Eugene Water & Electric Board	SF	WSPP-1			
28	Exelon Generation Company, LLC	SF	EEI			
29	Gridforce Energy Management	SF	NWPP			
30	Guzman Energy LLC	SF	WSPP-1			
31	Idaho Power Company	SF	WSPP-1			
32	Macquarie Energy LLC	SF	WSPP-1			
33	Mercuria Energy America, LLC	SF	WSPP-1			
34	Merrill Lynch Commodities	SF	WSPP-1			
35	Morgan Stanley Capital Group, Inc.	SF	PGE-11			
36	NaturEner Power Watch, LLC	SF	NWPP			
37	NorthWestern Corporation	SF	WSPP-1			
38	PacifiCorp	SF	EEI			
39	PacifiCorp	LU	PGE-11			
40	Powerex Corp.	SF	EEI			
41	Orange County	OS	WSPP-1			
42	Public Utility District No. 1 of Clark County	SF	WSPP-1			
43	Public Service Company of Colorado	SF	WSPP-1			
44	Rainbow Energy Marketing Company	SF	WSPP-1			
45	San Jose Clean Energy	OS	WSPP-1			
46	Sacramento Municipal Utility District	OS	WSPP-1			
47	Shell Energy North America (US), L.P.	SF	PGE-11			
48	Shell Energy North America (US), L.P.	OS	WSPP-1			
49	Sonoma Clean Power Authority	OS	WSPP-1			
50	Tenaska Power Services Co.	SF	WSPP-1			
51	The Energy Authority, Inc.	SF	WSPP-1			
52	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI			
53	TransCanada Energy Sales Ltd.	SF	WSPP-1			
54	Turlock Irrigation District	SF	WSPP-1			
55	Vitol Inc.	SF	WSPP-1			

SALES FOR RESALE (Account 447)

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)	ACTUAL DEMAND (MW)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
56	Umatilla Electric Cooperative	SF	EEI			
57	Direct Access deferral 2024-2025					
58	Direct Access Deferral 2023-2024					
59	^(a) Portland General Electric Total	SF	OA96137	143.7252		
15	Subtotal - RQ					
16	Subtotal-Non-RQ					
17	Total					

SALES FOR RESALE (Account 447)

Line No.	Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	535	0	116,241	0	116,241
2	122,658	0	4,928,477	0	4,928,477
3	5,400	0	254,644	0	254,644
4	1,148	0	47,920	0	47,920
5	143,505	0	5,919,399	0	5,919,399
6	596,148	0	27,884,713	0	27,884,713
7	33,527	0	1,262,510	0	1,262,510
8	74,774	0	2,845,195	0	2,845,195
9	2,000	0	112,085	0	112,085
10	591,440	0	19,738,774	0	19,738,774
11	24	0	1,209	0	1,209
12	73,283	0	3,033,005	0	3,033,005
13	2,316,938	0	84,649,592	0	84,649,592
14	348,623	0	6,214,259	0	6,214,259
15	1,008	0	37,104	0	37,104
16	15,320	0	617,340	0	617,340
17	18,000	0	679,040	0	679,040
18	318	0	17,780	0	17,780
19	6,749	0	267,352	0	267,352
20	67,666	0	2,973,676	0	2,973,676
21	9,141	0	465,694	0	465,694
22	1,171,274	0	10,381,591	0	10,381,591
23	527,412	0	21,839,159	0	21,839,159
24	8,437	0	437,731	0	437,731
25	12,520	0	411,562	0	411,562
26	150	0	6,925	0	6,925
27	25,516	0	1,083,342	0	1,083,342
28	36,952	0	1,460,306	0	1,460,306
29	434	0	19,918	0	19,918
30	11,015	0	586,876	0	586,876
31	82,678	0	2,679,704	0	2,679,704
32	63,050	0	2,652,042	0	2,652,042

SALES FOR RESALE (Account 447)

Line No.	Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
33	139,575	0	7,688,963	0	7,688,963
34	19,748	0	862,700	0	862,700
35	86,270	0	3,341,240	0	3,341,240
36	18	0	261	0	261
37	27,290	0	1,245,949	0	1,245,949
38	119,080	0	4,755,784	0	4,755,784
39	16,990	0	349,071	0	349,071
40	621,933	0	19,584,873	0	19,584,873
41	162,880	0	8,384,492	0	8,384,492
42	31,406	0	1,129,596	0	1,129,596
43	1,264,693	0	114,232,410	0	114,232,410
44	24,834	0	865,156	0	865,156
45	929	0	32,503	0	32,503
46	264	0	13,827	0	13,827
47	28,311	0	1,162,658	0	1,162,658
48	355,382	0	14,100,577	0	14,100,577
49	6,223	0	267,042	0	267,042
50	4,024	0	96,055	0	96,055
51	5,205	0	207,372	0	207,372
52	180,128	0	7,307,683	0	7,307,683
53	311,876	0	12,708,803	0	12,708,803
54	11,154	0	504,576	0	504,576
55	42,082	0	2,399,304	0	2,399,304
56	28,413	0	933,392	0	933,392
57	0	0	0	1,010,451	1,010,451
58	0	0	0	(548,193)	(548,193)
59	0	0	0	0	0
15					0
16	9,856,351	0	405,799,452	462,258	406,261,710
17	9,856,351	0	405,799,452	462,258	406,261,710

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Represents Portland General Electric Company's 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: RevenueFromSalesOfElectricityForResale

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

(c) Concept: RevenueFromSalesOfElectricityForResale

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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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	75,405	(19,472)
5	(501) Fuel	45,578,906	44,941,266
6	(502) Steam Expenses	1,968,474	1,927,250
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	18,705,540	4,353,002
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	66,328,325	51,202,046
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	612,936	550,751
16	(511) Maintenance of Structures	1,228,531	1,146,854
17	(512) Maintenance of Boiler Plant	12,168,253	11,072,782
18	(513) Maintenance of Electric Plant	1,712,020	1,808,495
18.1	(513.1) Maintenance of Computer Hardware	4	
18.2	(513.2) Maintenance of Computer Software	715,082	
18.3	(513.3) Maintenance of Communication Equipment	2,143	
19	(514) Maintenance of Miscellaneous Steam Plant	812,820	665,313
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	17,251,789	15,244,195
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	83,580,114	66,446,241
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		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
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)	0	
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		
38.1	(531.1) Maintenance of Computer Hardware		
38.2	(531.2) Maintenance of Computer Software		
38.3	(531.3) Maintenance of Communication Equipment		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0	
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	0	
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,215,152	1,508,981
45	(536) Water for Power	1,015,433	648,128
46	(537) Hydraulic Expenses	7,613,405	8,064,162
47	(538) Electric Expenses	1,816,671	1,732,650
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,621,169	5,701,559
49	(540) Rents	1,460,971	1,203,744
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	14,742,801	18,859,224
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	511,587	1,091,789
54	(542) Maintenance of Structures	3,018	2,051
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,198,699	1,855,418
56	(544) Maintenance of Electric Plant	1,029,498	1,280,134

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
56.1	(544.1) Maintenance of Computer Hardware	22,797	
56.2	(544.2) Maintenance of Computer Software	3,083,151	
56.3	(544.3) Maintenance of Communication Equipment	319,061	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,474,162	3,204,595
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,641,973	7,433,987
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	23,384,774	26,293,211
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	2,724,108	3,300,300
63	(547) Fuel	430,180,885	412,823,864
64	(548) Generation Expenses	16,227,904	15,352,608
65	(549) Miscellaneous Other Power Generation Expenses	4,616,897	21,518,284
66	(550) Rents	406,151	466,602
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	454,155,945	453,461,658
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,513,587	2,105,461
70	(552) Maintenance of Structures	331,523	710,948
71	(553) Maintenance of Generating and Electric Plant	31,993,934	49,718,253
71.1	(553.1) Maintenance of Computer Hardware	44,225	
71.2	(553.2) Maintenance of Computer Software	4,939,566	
71.3	(553.3) Maintenance of Communication Equipment	403,734	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,080,614	1,388,770
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	40,307,183	53,923,432
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	494,463,128	507,385,090
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	823,981,794	879,859,761
76.1	(555.1) Power Purchased for Storage Operations	22,014,474	
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits	2,438,900	
77	(556) System Control and Load Dispatching		85,796
78	(557) Other Expenses	28,162,326	33,806,989

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	876,597,494	913,752,546
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	21	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	4,717	
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	4,738	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		
79.11	(558.8) Maintenance of Computer Hardware	1	
79.12	(558.9) Maintenance of Computer Software	165	
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant	564	
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	730	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	5,468	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering	3,774,551	
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses	816,013	
79.21	(558.16) Rents	51,755	
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)	4,642,319	
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering	138,376	
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment	1,627,860	
79.26	(558.20) Maintenance of Computer Hardware	2,752	
79.27	(558.21) Maintenance of Computer Software	355,827	
79.28	(558.22) Maintenance of Communication Equipment	33,998	
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant	18,489,891	

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)	20,648,704	
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)	25,291,023	
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)	0	
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)	0	
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)	0	
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	1,503,322,001	1,513,877,088
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,150,139	5,134,747
85	(561.1) Load Dispatch-Reliability	24,207	16,278
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,871,900	1,946,997
87	(561.3) Load Dispatch-Transmission Service and Scheduling	2,115,946	2,396,290
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	11,612	130,926
90	(561.6) Transmission Service Studies	459,030	1,554

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
91	(561.7) Generation Interconnection Studies	1,650,314	833,374
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	330,672	412,928
94	(563) Overhead Lines Expenses	1,169,866	942,895
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	142,765,434	133,286,845
97	(566) Miscellaneous Transmission Expenses	(6,297,422)	714,483
98	(567) Rents	2,899,522	3,331,468
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	154,151,220	149,148,785
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	130,589	185,609
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	21,862	
104	(569.2) Maintenance of Computer Software	1,791,797	456,950
105	(569.3) Maintenance of Communication Equipment	272,890	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,501,377	2,403,828
108	(571) Maintenance of Overhead Lines	8,074,687	6,609,506
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	12,793,202	9,655,893
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	166,944,422	158,804,678
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		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	0	
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)	0	
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	0	
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering	157,372	
131.4	(577.2) Operation of Energy Storage Equipment	138,089	
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents	50,135	
131.7	Total Operation (Lines 131.3 thru 131.6)	345,596	
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering	346,175	
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures	3,172,689	
131.11	(578.3) Maintenance of Computer Hardware	1,038	
131.12	(578.4) Maintenance of Computer Software	145,081	
131.13	(578.5) Maintenance of Communication Equipment	15,057	
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant	158,303	
131.15	Total Maintenance (Lines 131.9 thru 131.14)	3,838,343	
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)	4,183,939	
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	14,025,274	14,493,893
135	(581) Load Dispatching	2,097,643	1,988,611

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
136	(582) Station Expenses	632,792	572,797
137	(583) Overhead Line Expenses	3,181,610	3,087,865
138	(584) Underground Line Expenses	5,077,140	5,229,646
139	(585) Street Lighting and Signal System Expenses	123,748	282,807
140	(586) Meter Expenses	2,830,311	2,893,636
141	(587) Customer Installations Expenses	1,031,078	2,031,653
142	(588) Miscellaneous Expenses	13,996,484	13,391,406
143	(589) Rents	1,227,092	1,917,996
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	44,223,172	45,890,310
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	9,682,369	7,087,550
147	(591) Maintenance of Structures	252,117	276,588
148	(592) Maintenance of Station Equipment	6,821,889	7,362,864
148.1	(592.2) Maintenance of Computer Hardware	99,475	
148.2	(592.3) Maintenance of Computer Software	9,540,055	
148.3	(592.4) Maintenance of Communication Equipment	1,361,303	
149	(593) Maintenance of Overhead Lines	163,797,341	141,052,908
150	(594) Maintenance of Underground Lines	8,482,826	16,959,864
151	(595) Maintenance of Line Transformers	1,229,541	1,158,893
152	(596) Maintenance of Street Lighting and Signal Systems	799,705	737,776
153	(597) Maintenance of Meters	36,138	30,022
154	(598) Maintenance of Miscellaneous Distribution Plant	60,391	7,757,151
155	TOTAL Maintenance (Total of Lines 146 thru 154)	202,163,150	182,437,648
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	246,386,322	228,327,958
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	96,078	229,025
161	(903) Customer Records and Collection Expenses	37,945,778	51,327,753
162	(904) Uncollectible Accounts	11,441,741	24,616,881
163	(905) Miscellaneous Customer Accounts Expenses	6,893,324	8,790,163
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	56,376,921	84,963,822

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	24,820,894	26,885,040
169	(909) Informational and Instructional Expenses	1,496,674	1,998,021
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	26,317,568	28,883,061
172	8. 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)	0	
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	160,545,819	158,308,949
182	(921) Office Supplies and Expenses	12,493,527	9,396,637
183	(Less) (922) Administrative Expenses Transferred-Credit	48,772,274	33,977,142
184	(923) Outside Services Employed	41,513,539	28,719,119
185	(924) Property Insurance	3,676,943	5,441,537
186	(925) Injuries and Damages	10,224,003	11,577,752
187	(926) Employee Pensions and Benefits	49,292,953	46,102,197
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	21,880,556	18,469,839
190	(929) (Less) Duplicate Charges-Cr.	4,125,973	3,604,720
191	(930.1) General Advertising Expenses	261,063	643,142
192	(930.2) Miscellaneous General Expenses	15,700,063	15,751,649
193	(931) Rents	783,327	813,781
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	263,473,546	257,642,740
195	Maintenance		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
196	(935) Maintenance of General Plant	4,907,642	5,755,040
196.1	(935.1) Maintenance of Computer Hardware	136,779	
196.2	(935.2) Maintenance of Computer Software	13,413,906	
196.3	(935.3) Maintenance of Communication Equipment	1,900,002	
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	20,358,329	
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	283,831,875	263,397,780
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	2,287,363,048	2,278,254,387

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
1	Airport Solar, LLC	LU	201				103,836
2	Alkali Solar	LU	201				28,286
3	Altop Energy Trading	SF	WSPP-1				10,223
4	Avangrid Renewables (was Iberdrola)	SF	PGE-11				50,563
5	Avangrid Renewables (was berdrola Renewables)	LU	PGE-11				179,373
6	Avista Corp. - AVWP (was WWP)	SF	WSPP-1				45,716
7	Atlas Energy	SF	EEl				32,548
8	BP Energy Company	SF	PGE-11				1,830
9	Brightwood Solar	LU	201				18,134
10	Ballston Solar	LU	201				3,659
11	Bonneville Power Administration	SF	WSPP-1				95,363
12	Bonneville Power Administration	LF	WSPP-1				1,029,208
13	Bonneville Power Administration	SF	WSPP-1				0
14	Boring Solar	LU	201				3,861
15	Brookfield Energy Marketing	SF	WSPP-1				26,708
16	CP Energy Marketing (US)	SF	WSPP-1				15,751
17	California Independent System Operator	SF	CAISO				1,825,275
18	Calpine Energy Services	SF	PGE-11				1,085,163
19	Case Creek Solar	LU	201				3,722
20	Bristol Solar LLC	LU	201				4,512
21	Butler Solar	LU	201				8,281
22	Chelan County, PUD No. 1, Washington	SF	WSPP-1				32,812
23	Citigroup Energy	SF	WSPP-1				1,200
24	Clatskanie County PUD	SF	WSPP-1				4,981
25	Clearwater East	LU	WSPP-1				400,702

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
26	Columbia Basin Electric Cooperative Inc.	LU	OATT				843
27	ConocoPhillips	SF	WSPP-1				35,218
28	Day Hill Solar	LU	201				3,990
29	Dynasty Power Inc.	SF	WSPP-1				22,035
30	Douglas County, PUD No. 1, Washington	LF	WSPP-1				2,340,563
31	Douglas County, PUD No. 1, Washington	SF	WSPP-1				0
32	EDF Trading North America, LLC	SF	WSPP-1				1,048
33	Energy Keepers, Inc. - ENKP	SF	WSPP-1				400
34	ENMAX Energy Marketing	SF	PGE-11				1,636
35	ESI Vansycle Partners, LP	LU	WSPP-1				54,901
36	Eugene Water & Electric Board	SF	ER94-717				30,083
37	Evergreen Biomass	LU	201				48,872
38	Exelon Generation Co.	SF	WSPP-1				10,489
39	Falls Creek Hydro	LU	201				11,930
40	Finley BioEnergy, LLC	LU	201				13,099
41	Fort Rock Solar 1	LU	201				28,546
42	Fort Rock Solar 4	LU	201				27,767
43	Gridforce Energy Management - GRID	SF	201				20
44	Idaho Power Company	SF	NWPP				12,295
45	Labish Solar	LU	WSPP-1				3,823
46	Macquarie Cook Power	SF	201				16,000
47	Mercuria Energy America, LLC	SF	WSPP-1				159,241
48	Merrill Lynch Commodities	SF	WSPP-1				400
49	Milford Solar	LU	201				4,198
50	Middlefork Irrigation District	LU	201				16,685
51	Morgan Stanley Capital Group	SF	PGE-11				16,804
52	Montague Solar	LU	WSPP-1				393,865

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
53	NorthWestern Corporation	SF	WSPP-1				(188)
54	Norwest Energy 14	LU	201				3,931
55	Obsidian Lakeview	LU	201				24,454
56	OE Solar 3, LLC	LU	201				28,204
57	Okanogan County PUD, Washington	LF	WSPP-1				289,283
58	O'Neil Solar	LU	201				3,399
59	Outback Solar	LU	Outback				6,456
60	Pacific Northwest Generating Company	LU	PGNC				44,643
61	PacifiCorp	SF	PGE-11				4,889
62	Palmer Creek Solar	LU	201				3,425
63	Pika Solar	LU	201				3,851
64	PaTu Wind	LU	WSPP-1				28,706
65	Phillips 66 Energy Trading LLC	LU	201				17,371
66	Duus Solar (Alchemy)	LU	201				38,763
67	Portland, City of	LU	#2821				62,894
68	Powerex	SF	PGE-11				35,890
69	Grant County, PUD No. 2, Washington	LU	Wanapum				1,315,558
70	Grant County, PUD No. 2, Washington	LU	Priest Rapids				1,315,558
71	Grant County, PUD No. 2, Washington	LU	WSPP-1				0
72	Greenpark Solar, LLC	LU	201				1,890
73	Guzman Energy LLC	SF	WSPP-1				1,167
74	City of Glendale	SF	WSPP-1				75
75	Puget Sound Energy	SF	WSPP-1				39,124
76	Rafael Solar	LU	201				3,663
77	Riley Solar	LU	201				27,376
78	Rock Garden Solar	LU	201				27,464
79	Seattle City Light	SF	WSPP-1				9,665

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
80	Shell Energy	SF	WSPP-1				45,493
81	Sheep Solar	LU	201				3,815
82	Silverton Solar	LU	201				3,783
83	Sacramento Municipal Utility District	SF	WSPP-1				2,010
84	Snohomish County, PUD No. 1, Washington	SF	WSPP-1				11,830
85	SP Solar 1, LLC	LU	201				3,481
86	SP Solar 5, LLC	LU	201				3,797
87	SP Solar 6, LLC	LU	201				3,691
88	SP Solar 7, LLC	LU	201				3,365
89	SP Solar 8, LLC	LU	201				3,670
90	SSD Clackamas 1	LU	201				6,614
91	SSD Clackamas 4	LU	201				4,232
92	SSD Clackamas 7	LU	201				3,951
93	SSD Marion 1	LU	201				3,903
94	SSD Marion 3	LU	201				4,100
95	SSD Marion 5	LU	201				4,079
96	SSD Marion 6	LU	201				4,006
97	Steel Bridge	LU	201				3,308
98	Starvation Solar 1 LLC	LU	201				26,918
99	St Louis Solar	LU	201				3,912
100	Suluss Solar 35	LU	201				4,610
101	Suluss Solar 33	LU	201				4,567
102	Suluss Solar 22	LU	201				4,803
103	Suluss Solar 25	LU	201				3,320
104	Suluss Solar 28	LU	201				1,789
105	Suluss Solar 29	LU	201				3,754
106	Suluss Solar 17	LU	201				4,168
107	Suntex Solar	LU	201				27,071

PURCHASED POWER (Account 555)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
108	West Hines Solar	LU	201				25,928
109	Tacoma, City of	SF	WSPP-1				33,069
110	The Energy Authority	SF	WSPP-1				28,143
111	Thomas Creek Solar	LU	201				3,694
112	Tickle Creek	LU	201				2,966
113	TransAlta Energy Marketing	SF	PGE-11				32,086
114	TransCanada Energy Marketing	SF	WSPP-1				1,993
115	Turlock Irrigation District	SF	WSPP-1				32,086
116	Vitol Inc.	SF	WSPP-1				4,378
117	Volcano Solar	LU	201				1,387
118	VON FAMILY LTD PARTNERSHIP	LU	201				(1)
119	Warm Springs Power Enterprises	LU	WSPP-1				657,657
120	Warm Springs Power Enterprises	LU	WSPP-1				0
121	Wheatridge Solar	LU	WSPP-1				133,178
122	Wheatridge Wind II, LLC	LU	WSPP-1				542,072
123	Nextera Energy Capital Holdings Inc	LU	WSPP-1				0
124	Kale Patch Solar	LU	201				3,814
125	Drift Creek	LU	201				13,660
126	^(a) Load Balance Energy	OS	OATT				443,903
127	Country Village Estates	^(d) OS	201				0
128	Domaine Drouhin	^(e) OS	201				38
129	Starbuck Properties	^(f) OS	201				0
130	Solar Payment Option	^(g) OS	215-217				276,011
131	Tualatin Valley Water Dist	^(h) OS	201				338
132	Green Power						0
133	NVPC MONET QF Deferrals						0

PURCHASED POWER (Account 555)

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)	Actual Demand (MW)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
134	Margin on Electric Financials						0
135	Pelton Round Butte Finance Lease 49.9%						0
136	Wheatridge Battery Lease						0
137	PCAM Deferrals	AD					0
138	REC Retirement Expense						0
139	Carbon Allowance Expense						0
15	TOTAL						14,044,409

PURCHASED POWER (Account 555)

Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	POWER EXCHANGES	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1	0	0	0	0	8,508,371	0	8,508,371
2	0	0	0	0	2,567,681	0	2,567,681
3	0	0	0	0	1,222,350	0	1,222,350
4	0	0	0	0	2,699,462	0	2,699,462
5	0	0	0	0	12,373,940	0	12,373,940
6	0	0	0	0	706,673	0	706,673
7	0	0	0	0	1,736,022	0	1,736,022
8	0	0	0	0	85,794	0	85,794
9	0	0	0	0	1,674,554	0	1,674,554
10	0	0	0	0	326,742	0	326,742
11	0	0	0	0	1,552,733	0	1,552,733
12	0	0	0	0	45,353,336	0	45,353,336
13	0	0	0	10,895,415	0	0	10,895,415
14	0	0	0	0	342,647	0	342,647
15	0	0	0	0	890,685	0	890,685
16	0	0	0	0	468,427	0	468,427
17	0	0	0	0	45,458,838	0	45,458,838
18	0	0	0	48,405,000	16,830,585	0	65,235,585
19	0	0	0	0	336,563	0	336,563
20	0	0	0	0	322,717	0	322,717
21	0	0	0	0	900,697	0	900,697
22	0	0	0	0	2,832,035	0	2,832,035
23	0	0	0	0	58,000	0	58,000
24	0	0	0	0	154,658	0	154,658
25	0	0	0	0	15,066,639	0	15,066,639
26	0	0	0	0	128,114	0	128,114
27	0	0	0	0	679,428	0	679,428
28	0	0	0	0	294,291	0	294,291
29	0	0	0	0	587,829	0	587,829
30	0	0	0	0	83,714,729	0	83,714,729

PURCHASED POWER (Account 555)

Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	POWER EXCHANGES	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
31	0	0	0	23,299,067	0	0	23,299,067
32	0	0	0	0	37,728	0	37,728
33	0	0	0	0	5,200	0	5,200
34	0	0	0	0	52,340	0	52,340
35	0	0	0	0	4,456,834	0	4,456,834
36	0	0	0	0	2,082,726	0	2,082,726
37	0	0	0	0	4,999,975	0	4,999,975
38	0	0	0	0	218,052	0	218,052
39	0	0	0	0	1,081,656	0	1,081,656
40	0	0	0	0	636,173	0	636,173
41	0	0	0	0	2,691,875	0	2,691,875
42	0	0	0	0	2,602,363	0	2,602,363
43	0	0	0	0	1,478	0	1,478
44	0	0	0	0	387,657	0	387,657
45	0	0	0	0	263,893	0	263,893
46	0	0	0	0	1,057,404	0	1,057,404
47	0	0	0	0	13,135,101	0	13,135,101
48	0	0	0	0	9,900	0	9,900
49	0	0	0	0	293,695	0	293,695
50	0	0	0	0	1,371,374	0	1,371,374
51	0	0	0	0	368,810	0	368,810
52	0	0	0	0	16,639,833	0	16,639,833
53	0	0	0	0	220,924	0	220,924
54	0	0	0	0	413,340	0	413,340
55	0	0	0	0	2,424,844	0	2,424,844
56	0	0	0	0	2,377,687	0	2,377,687
57	0	0	0	0	8,333,599	0	8,333,599
58	0	0	0	0	310,786	0	310,786
59	0	0	0	0	720,558	0	720,558
60	0	0	0	0	4,256,197	0	4,256,197

PURCHASED POWER (Account 555)

Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	POWER EXCHANGES	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
61	0	0	0	0	147,478	0	147,478
62	0	0	0	0	299,233	0	299,233
63	0	0	0	0	205,232	0	205,232
64	0	0	0	0	2,617,646	0	2,617,646
65	0	0	0	0	969,700	0	969,700
66	0	0	0	0	4,397,907	0	4,397,907
67	0	0	0	0	2,874,873	0	2,874,873
68	0	0	0	0	2,014,140	0	2,014,140
69	0	0	0	0	97,679,387	0	97,679,387
70	0	0	0	0	97,679,387	0	97,679,387
71	0	0	0	90,322,980	0	0	90,322,980
72	0	0	0	0	151,698	0	151,698
73	0	0	0	0	242,939	0	242,939
74	0	0	0	0	1,320	0	1,320
75	0	0	0	0	1,015,777	0	1,015,777
76	0	0	0	0	335,231	0	335,231
77	0	0	0	0	2,576,966	0	2,576,966
78	0	0	0	0	2,469,054	0	2,469,054
79	0	0	0	0	250,428	0	250,428
80	0	0	0	0	2,939,031	0	2,939,031
81	0	0	0	0	374,688	0	374,688
82	0	0	0	0	375,116	0	375,116
83	0	0	0	0	52,135	0	52,135
84	0	0	0	0	275,835	0	275,835
85	0	0	0	0	334,895	0	334,895
86	0	0	0	0	404,685	0	404,685
87	0	0	0	0	324,101	0	324,101
88	0	0	0	0	361,253	0	361,253
89	0	0	0	0	449,537	0	449,537
90	0	0	0	0	547,895	0	547,895

PURCHASED POWER (Account 555)

Line No.	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	POWER EXCHANGES	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER	COST/SETTLEMENT OF POWER
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
91	0	0	0	0	321,832	0	321,832
92	0	0	0	0	303,188	0	303,188
93	0	0	0	0	335,142	0	335,142
94	0	0	0	0	291,700	0	291,700
95	0	0	0	0	300,508	0	300,508
96	0	0	0	0	304,723	0	304,723
97	0	0	0	0	298,840	0	298,840
98	0	0	0	0	2,516,013	0	2,516,013
99	0	0	0	0	338,436	0	338,436
100	0	0	0	0	371,031	0	371,031
101	0	0	0	0	343,997	0	343,997
102	0	0	0	0	370,832	0	370,832
103	0	0	0	0	272,026	0	272,026
104	0	0	0	0	314,514	0	314,514
105	0	0	0	0	313,426	0	313,426
106	0	0	0	0	388,990	0	388,990
107	0	0	0	0	2,621,995	0	2,621,995
108	0	0	0	0	2,549,469	0	2,549,469
109	0	0	0	0	1,029,797	0	1,029,797
110	0	0	0	0	812,991	0	812,991
111	0	0	0	0	272,543	0	272,543
112	0	0	0	0	193,716	0	193,716
113	0	0	0	0	656,168	0	656,168
114	0	0	0	0	68,255	0	68,255
115	0	0	0	0	545,700	0	545,700
116	0	0	0	0	159,133	0	159,133
117	0	0	0	0	87,058	0	87,058
118	0	0	0	0	7,654	0	7,654
119	0	0	0	0	26,520,042	0	26,520,042
120	0	0	0	888,001	0	0	888,001

PURCHASED POWER (Account 555)

Line No.	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)	COST/SETTLEMENT OF POWER Energy Charges (\$) (l)	COST/SETTLEMENT OF POWER Other Charges (\$) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement (\$) (n)
	121	0	0	0	0	76,092	0
122	0	0	0	0	24,983,711	0	24,983,711
123	0	0	0	37,817,362	0	0	37,817,362
124	0	0	0	0	278,184	0	278,184
125	0	0	0	0	1,328,889	0	1,328,889
126	0	0	0	0	0	0	0
127	0	0	0	0	116,643	0	116,643
128	0	0	0	0	1,223	0	1,223
129	0	0	0	0	834	0	834
130	0	0	0	0	6,947,438	0	6,947,438
131	0	0	0	0	3,859	0	3,859
132	0	0	0	0	0	8,636,460	8,636,460
133	0	0	0	0	0	648,000	648,000
134	0	0	0	0	0	(11,240,220)	(11,240,220)
135	0	0	0	0	0	17,496,206	17,496,206
136	0	0	0	0	0	1,923,900	1,923,900
137	0	0	0	0	0	3,812,852	3,812,852
138	0	0	0	0	0	659,434	659,434
139	0	0	0	0	0	(3,469,992)	(3,469,992)
15	0	0	0	211,627,825	618,340,701	18,466,640	848,435,166

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ 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
Footnote: The Douglas County contract expires on 12/31/2025
(c) Concept: StatisticalClassificationCode
Footnote: 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: OtherChargesOfPurchasedPower
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: OtherChargesOfPurchasedPower
NVPC MONET QF Deferrals & Cure Payments
(k) Concept: OtherChargesOfPurchasedPower
Margin on electric financial transactions.
(l) Concept: OtherChargesOfPurchasedPower
Pelton Round Butte Financial Lease amortization and interest
(m) Concept: OtherChargesOfPurchasedPower
Wheatridge Battery Lease amortization.
(n) Concept: OtherChargesOfPurchasedPower
PCAM Deferrals
(o) Concept: OtherChargesOfPurchasedPower
Expense of annual REC retirement to meet RPS compliance.
(p) Concept: OtherChargesOfPurchasedPower

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

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

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Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

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)
1	BPA Power Business Line	Bonneville Power Administration	West Oregon Electric Coop Total	OLF	72	BPAT.PGE	Various
2	BPA Power Business Line	Bonneville Power Administration	Other TVI Pumps Total	OLF	72	BPAT.PGE	Various
3	BPA Power Business Line	Bonneville Power Administration	Canby PUD Total	OLF	72	BPAT.PGE	Various
4	BPA Power Business Line	Bonneville Power Administration	Columbia River PUD Total	OLF	72	BPAT.PGE	Various
5	Pacificorp West	PacifiCorp	Portland General Electric	OLF	Exchange	PACW.PGE	Various
6	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
7	Avangrid Renewables, LLC			(e) OS	11		
8	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO	7	BPAT.PGE	Various Subs
9	BPA Power Business Line			(e) OS	11		
10	Brookfield Renewable Energy Marketing US LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
11	Brookfield Renewable Energy Marketing US LLC			(e) OS	11		
12	Calpine Energy Services	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
13	Calpine Energy Services			(e) OS	11		
14	Constellation New Energy	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
15	Constellation New Energy			(e) OS	11		
16	Shell Energy North America	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
17	Shell Energy North America			(e) OS	11		
18	Altop Energy Trading LLC	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay
19	Altop Energy Trading LLC	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack

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

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)
20	Altop Energy Trading LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
21	Altop Energy Trading LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
22	Altop Energy Trading LLC	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
23	Altop Energy Trading LLC	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay
24	Altop Energy Trading LLC			u OS	11		
25	Avista Corp	California Independent System Operator	Bonneville Power Administration	LFP	7	JohnDay	Malin500
26	Avista Corp	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
27	Avista Corp	California Independent System Operator	Bonneville Power Administration	u OS	8	Malin500	JohnDay
28	Avista Corp			u OS	11		
29	Brookfield Renewable Trading and Marketing LP	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
30	Brookfield Renewable Trading and Marketing LP			u OS	11		
31	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
32	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500
33	Shell Energy North America	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE
34	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
35	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
36	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
37	Shell Energy North America	Balancing Authority of Northern California	Bonneville Power Administration	m OS	8	CaptainJack	JohnDay
38	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	u OS	8	Malin500	JohnDay
39	Shell Energy North America			u OS	11		

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

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)
40	NRG Business Marketing LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
41	NRG Business Marketing LLC			^(a) OS	11		
42	Dynasty Power Inc	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE
43	Dynasty Power Inc	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
44	Dynasty Power Inc			^(a) OS	11		
45	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
46	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500
47	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
48	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
49	Constellation New Energy	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
50	Constellation New Energy			^(a) OS	11		
51	Mag Energy Solutions	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay
52	Mag Energy Solutions	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
53	Mag Energy Solutions	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
54	Mag Energy Solutions	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
55	Mag Energy Solutions			^(a) OS	11		
56	Macquarie Energy LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
57	Macquarie Energy LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
58	Macquarie Energy LLC			^(a) OS	11		
59	Mercuria Energy America, LLC	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay
60	Mercuria Energy America, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500

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

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)
61	Mercuria Energy America, LLC			OS	11		
62	MFT Energy US Power LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
63	MFT Energy US Power LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
64	MFT Energy US Power LLC			OS	11		
65	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
66	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500
67	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
68	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
69	Morgan Stanley Capital Group			OS	11		
70	Pacificorp West	Portland General Electric	Bonneville Power Administration	LFP	7	RoundButte	REDMOND
71	Pacificorp West	Portland General Electric	Bonneville Power Administration	NF	8	RoundButte	REDMOND
72	Pacificorp West			OS	11		
73	Avangrid Renewables, LLC	Bonneville Power Administration	California Independent System Operator	LFP	8	Malin500	JohnDay
74	Avangrid Renewables, LLC			OS	11		
75	Puget Sound Energy	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
76	Puget Sound Energy	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
77	Puget Sound Energy			OS	11		
78	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
79	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500
80	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
81	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	OS	8	Malin500	JohnDay

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

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)
82	Powerex Inc.			(a) OS	11		
83	Rainbow Energy Marketing Corp	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
84	Rainbow Energy Marketing Corp	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
85	Rainbow Energy Marketing Corp			(a) OS	11		
86	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
87	Seattle City Light	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
88	Seattle City Light	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
89	Seattle City Light			(a) OS	11		
90	Sacramento Municipal Utility Dist.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay
91	Sacramento Municipal Utility Dist.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
92	Sacramento Municipal Utility Dist.			(a) OS	11		
93	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
94	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack
95	The Energy Authority	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE
96	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay
97	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
98	The Energy Authority	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
99	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
100	The Energy Authority	Portland General Electric	Bonneville Power Administration	NF	8	PGE	BPAT.PGE
101	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	(a) OS	8	CaptainJack	JohnDay
102	The Energy Authority	California Independent System Operator	Bonneville Power Administration	(a) OS	8	Malin500	JohnDay

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

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)
103	The Energy Authority			(a) OS	11		
104	Transalta Energy Marketing (US) Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
105	Transalta Energy Marketing (US) Inc.			(b) OS	11		
106	Turlock Irrigation Dist	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
107	Turlock Irrigation Dist	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
108	Turlock Irrigation Dist			(c) OS	11		
109	Tacoma Power	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
110	Tacoma Power	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
111	Tacoma Power	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
112	Tacoma Power			(d) OS	11		
113	Vitol Inc	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
114	Vitol Inc	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
115	Vitol Inc			(e) OS	11		
116	Public Utility District No. 1 of Cowlitz County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH
117	Public Utility District No. 1 of Franklin County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH
118	Public Utility District No. 1 of Klickitat County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH
119	Public Utility District No. 1 of Lewis County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH
120	(a) Accrual			OS			
121	(b) Deferral						
35	TOTAL						

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

Line No.	TRANSFER OF ENERGY		TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)	
1	0	14,173	14,165	0	0	(a)110,241	110,241	
2	0	7,831	7,621	0	0	(as)29,129	29,129	
3	0	215,104	205,412	0	0	(at)438,712	438,712	
4	0	189,877	189,768	0	0	(au)17,687	17,687	
5	0	3,235	3,228	0	0	(av)225,941	225,941	
6	169	108,183	108,183	144,366	(al)(3,399)	(aw)66,291	207,258	
7	0	0	0	0	64,540	0	64,540	
8	174	86,113	86,113	148,211	(am)94,570	(ax)68,421	311,202	
9	0	0	0	0	52,615	0	52,615	
10	117	76,139	76,139	99,725	(an)(112,921)	(ay)45,859	32,663	
11	0	0	0	0	45,438	0	45,438	
12	2,400	1,681,314	1,681,314	2,048,535	(ao)(3,879,066)	(az)941,059	(889,472)	
13	0	0	0	0	997,275	0	997,275	
14	1,206	864,164	864,164	1,027,967	(ap)(459,013)	(ba)472,323	1,041,277	
15	0	0	0	0	502,574	0	502,574	
16	42	30,483	30,483	36,040	(aq)(268,392)	(bb)16,577	(215,775)	
17	0	0	0	0	17,511	0	17,511	
18	0	4,501	4,501	0	0	(bc)27,773	27,773	
19	0	222	222	0	0	(bd)1,370	1,370	
20	0	496	496	0	0	(be)3,061	3,061	
21	0	14,096	14,096	0	0	(bf)86,979	86,979	
22	0	11,368	11,368	0	0	(bg)14,604	14,604	
23	0	1,455	1,455	0	0	(bh)1,869	1,869	
24	0	0	0	0	22,546	0	22,546	
25	0	600	600	0	0	(bi)1,445,299	1,445,299	
26	0	600	600	0	0	(bj)1,075	1,075	
27	0	3,457	3,457	0	0	0	0	
28	0	0	0	0	1,812	0	1,812	
29	0	518	518	0	0	(bk)859	859	

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

Line No.	TRANSFER OF ENERGY		TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)	
30	0	0	0	0	413	0	413	
31	0	491,476	491,476	0	0	(b) 1,537,318	1,537,318	
32	0	432,640	432,640	0	0	(bm) 1,353,281	1,353,281	
33	0	6	6	0	0	(bn) 19	19	
34	0	1,414	1,414	0	0	(bo) 4,437	4,437	
35	0	458	458	0	0	(bp) 1,437	1,437	
36	0	1,411	1,411	0	0	(bq) 4,428	4,428	
37	0	57	57	0	0	0	0	
38	0	885	885	0	0	0	0	
39	0	0	0	0	566,655	0	566,655	
40	0	32	32	0		(br) 397	397	
41	0	0	0	0	13	0	13	
42	0	25	25	0		(bs) 18,272	18,272	
43	0	50	50	0	0	(bt) 36,543	36,543	
44	0	0	0	0	15	0	15	
45	0	715	715	0	0	(bu) 4,764	4,764	
46	0	20,977	20,977	0	0	(bv) 139,766	139,766	
47	0	160	160	0	0	(bw) 428	428	
48	0	4,060	4,060	0	0	(bx) 10,849	10,849	
49	0	2,909	2,909	0	0	(by) 7,773	7,773	
50	0	0	0	0	16,294	0	16,294	
51	0	203	203	0	0	(bz) 429	429	
52	0	33,213	33,213	0	0	(ca) 70,193	70,193	
53	0	61,445	61,445	0	0	(cb) 129,859	129,859	
54	0	6,814	6,814	0	0	(cc) 14,401	14,401	
55	0	0	0	0	52,261	0	52,261	
56	0	262	262	0	0	(cd) 680	680	
57	0	261	261	0	0	(ce) 677	677	
58	0	0	0	0	370	0	370	

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

Line No.	TRANSFER OF ENERGY		TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)	
59	0	3,852	3,852	0	0	(cl)240,883	240,883	
60	0	22	22	0	0	(ca)36	36	
61	0	0	0	0	5,811	0	5,811	
62	0	20	20	0	0	(ch)58	58	
63	0	1,323	1,323	0	0	(ci)3,804	3,804	
64	0	0	0	0	1,273	0	1,273	
65	0	7,892	7,892	0	0	(ci)27,091	27,091	
66	0	34,211	34,211	0	0	(cb)117,438	117,438	
67	0	7,797	7,797	0	0	(cl)18,803	18,803	
68	0	4,587	4,587	0	0	(cm)11,062	11,062	
69	0	0	0	0	33,336	0	33,336	
70	0	22,376	22,376	0	0	(cn)186,650	186,650	
71	0	5,871	5,871	0	0	(co)23,747	23,747	
72	0	0	0	0	11,856	0	11,856	
73	0	6,943	6,943	0	0	(ca)843,091	843,091	
74	0	0	0	0	5,067	0	5,067	
75	0	576	576	0	0	(ca)2,026	2,026	
76	0	3,075	3,075	0	0	(cl)10,813	10,813	
77	0	0	0	0	2,865	0	2,865	
78	0	37,377	37,377	0	0	(ca)512,997	512,997	
79	0	259,582	259,582	0	0	(cl)3,562,747	3,562,747	
80	0	3,694	3,694	0	0	(ca)26,264	26,264	
81	0	3,330	3,330	0	0	0	0	
82	0	0	0	0	205,812	0	205,812	
83	0	258	258	0	0	(cv)604	604	
84	0	3,368	3,368	0	0	(cw)7,890	7,890	
85	0	0	0	0	2,528	0	2,528	
86	0	698	698	0	0	(cx)26,619	26,619	
87	0	175	175	0	0	(cy)6,674	6,674	

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

Line No.	TRANSFER OF ENERGY		TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)	
88	0	548	548	0	0	(c2)20,899	20,899	
89	0	0	0	0	809	0	809	
90	0	450	50	0	0	(da)745	745	
91	0	50	460	0	0	(db)83	83	
92	0	0	0	0	182	0	182	
93	0	87,551	87,551	0	0	(dc)74,488	74,488	
94	0	82,326	82,326	0	0	(de)70,042	70,042	
95	0	76	76	0	0	(de)161	161	
96	0	3,529	3,529	0	0	(df)7,480	7,480	
97	0	5,248	5,248	0	0	(da)11,123	11,123	
98	0	31,942	31,942	0	0	(db)67,703	67,703	
99	0	5,739	5,739	0	0	(d)12,164	12,164	
100	0	71	71	0	0	(di)150	150	
101	0	252	252	0	0	0	0	
102	0	550	550	0	0	0	0	
103	0	0	0	0	130,938	0	130,938	
104	0	1,359	850	0	0	(dk)2,421	2,421	
105	0	0	0	0	829	0	829	
106	0	25,775	25,775	0	0	(d)44,778	44,778	
107	0	254	254	0	0	(dm)441	441	
108	0	0	0	0	14,939	0	14,939	
109	0	305	305	0	0	(dn)549	549	
110	0	10,051	10,051	0	0	(do)18,096	18,096	
111	0	179	179	0	0	(dp)322	322	
112	0	0	0	0	5,959	0	5,959	
113	0	15	15	0	0	(da)35	35	
114	0	19,901	19,901	0	0	(di)45,782	45,782	
115	0	0	0	0	14,294	0	14,294	
116		0	0	0	0	(ds)144,530	144,530	

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

Line No.	TRANSFER OF ENERGY		TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS
	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)	
117		0	0	0	0	144,530	144,530	
118		0	0	0	0	158,983	158,983	
119		0	0	0	0	158,983	158,983	
120					(475,051)	64,405	(410,646)	
121						9,384,603	9,384,603	
35	4,108	5,056,600	5,046,075	3,504,844	(2,326,442)	23,413,873	24,592,275	

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) 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.
(b) Concept: PaymentByCompanyOrPublicAuthority
Amortization of revenues previously deferred according to OPUC OrderNo. 22-129.
(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
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.
(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
Represents non-billed redirected MWhs.
(k) 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.
(l) 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.
(m) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(n) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.

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.
(ad) 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.
(ae) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(af) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ag) 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.
(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
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.
(ak) 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.
(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: 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.
(aq) 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.

[\(ar\)](#) 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 the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.

[\(au\)](#) 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.

[\(av\)](#) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Pre-888 contract executed between PGE and PacifiCorp concerning the exchange of transmission services over agreed-upon facilities.

[\(aw\)](#) 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.
Reactive supply and voltage control service.
Regulation and frequency response service.
Operating reserve - spinning reserve service.
Operating reserve - supplemental reserve service.

[\(ba\)](#) 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.

(bb) 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.

(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(bq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(br) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

[\(du\)](#) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

[\(dv\)](#) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY	TRANSFER OF ENERGY
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)
1	Bonneville Power Admin	^(a) LFP	0	0
2	Bonneville Power Admin	OS	348,553	348,553
3	Bonneville Power Admin	SFP	74,579	74,579
4	Bonneville Power Admin	NF	17,438	17,438
5	Arizona Public Service	NF	300	300
6	Avista Corp	NF	7,262	7,262
7	ALBERTA ELECTRIC SYSTEM OPERATOR	NF	1,380	1,380
8	Columbia River PUD	SFP	13	13
9	Eugene Water & Electric Board	^(b) LFP	12	12
10	Idaho Power Co	NF	5,581	5,581
11	LA Dept of Water & Power	NF	1,150	1,150
12	McMinnville Water & Light	^(a) LFP	913	913
13	Montana, State of	OS	0	0
14	Nextera Energy Capital Holdings Inc	OS	0	0
15	Nevada Power Company	NF	2,196	2,196
16	NorthWestern Energy	NF	5,281,235	5,281,235
17	PacifiCorp Linneman Substation	OS	0	0
18	PacifiCorp	SFP	256,889	256,889
19	Puget Sound Energy	NF	31,988	31,988
20	WESTERN AREA POWER	NF	1,323	1,323
21	Okanogan County PUD, Washington	NF	342,066	342,066
22	Tucson Electric Power	OS	0	0
23	Seattle City Light	NF	17,118	17,118
24	Sierra Pacific	NF	1,804	1,804
25	Snohomish County	SFP	3,572	3,572
26	UMATILLA ELECTRIC COOPERATIVE	OS	0	0
	TOTAL		6,395,372	6,395,372

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

Line No.	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS
	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	92,761,970			92,761,970
2			18,874,585	18,874,585
3		2,917,364		2,917,364
4		163,897		163,897
5		1,861		1,861
6		63,156		63,156
7		20,727		20,727
8		20,487		20,487
9		114,342		114,342
10		39,984		39,984
11		(90,033)		(90,033)
12		12,324		12,324
13			2,108,704	2,108,704
14			6,987,267	6,987,267
15		8,785		8,785
16		18,144,220		18,144,220
17		0	101,798	101,798
18		(32,069)		(32,069)
19		77,759		77,759
20		1,067		1,067
21		366,327		366,327
22			(243)	(243)
23		29,957		29,957
24		4,389		4,389
25		6,226		6,226
26			60,583	60,583
	92,761,970	21,870,770	28,132,694	142,765,434

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Represents Bonneville Power Administration PTP contracts that have termination dates that range from 7/1/2024 - 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 (no expiration date)

(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 PacificCorp Linneman Transmission Services.

(h) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents Tucson Electric Power Transmission Services.

(i) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents UMATILLA ELECTRIC COOPERATIVE Transmission Services.

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,943,053
2	Nuclear Power Research Expenses	0
3	Other Experimental and General Research Expenses	2,651,417
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,825,746
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Involuntary Severance	2,687,422
7	Directors Pension	117,740
8	Directors and Officers Expenses	3,516,668
9	Misc. Admin Expenses	252,733
10	Colstrip - PPL Montana	705,284
46	TOTAL	15,700,063

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

Line No.	Functional Classification (a)	A. Summary of Depreciation and Amortization Charges	A. Summary of Depreciation and Amortization Charges	A. Summary of Depreciation and Amortization Charges	A. Summary of Depreciation and Amortization Charges	A. Summary of Depreciation and Amortization Charges
		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			3,842,149		3,842,149
2	Steam Production Plant	40,663,249	395,609			41,058,858
3	Nuclear Production Plant					
4	Hydraulic Production Plant- Conventional	24,722,342	68			24,722,410
5	Hydraulic Production Plant- Pumped Storage					
5.1	Solar Production Plant	122,248	80,706			202,954
5.2	Wind Production Plant	63,079,181	352,267			63,431,448
5.3	Other Renewable Production Plant					
6	Other Production Plant	43,877,591	596,750			44,474,341
7	Transmission Plant	35,321,779				35,321,779
8	Distribution Plant	175,873,762	5,513			175,879,275
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant	24,771,108	115			24,771,223
10	General Plant	116,740,025				116,740,025
11	Common Plant-Electric					
12	TOTAL	525,171,285	1,431,028	3,842,149		530,444,462

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B. Basis for Amortization Charges

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

C. Factors Used in Estimating Depreciation Charges

Line No.	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	315.01.00- Computer,Laptop,Servers	70	5 years	0%	37.34%	Lifespan - 2025	0 years
13	334.01.00- Computer,Laptop,Servers	14	5 years	0%	37.34%	SQ	3 years

14	334.01.01-SCADA & RTU	10,451	15 years	0%	10.1%	SQ	10 years
15	334.03.01-Line Equipment	3,094	15 years	0%	8.56%	SQ	12 years
16	334.03.02-Radio, Microwave, Term Eq	3,468	15 years	0%	10.1%	SQ	10 years
17	334.03.03-Mobile Radio Equipment	0	15 years	0%	8.09%	SQ	12 years
18	334.03.04-Telephone Equipment	58	15 years	0%	12.79%	SQ	8 years
19	338.04.00-Solar Panels	1,423	20 years	(2)%	7.28%	L2.5	14 years
20	338.11.02-Radio, Microwave, Term Eq	686	15 years	0%	10.1%	SQ	10 years
21	338.13.00-ARC-Solar Production	1,459				SQ	
22	338.21.01-Biglow	34,490	30 years	(5)%	5.64%	R3	18 years
23	338.21.01-Clearwater	97,377	40 years	(3)%	3.47%	R4	48 years
24	338.21.01-Tucannon	18,888	30 years	(4)%	4.05%	R3	25 years
25	338.21.01-Wheatridge	3,441	40 years	(3)%	3.47%	R4	45 years
26	338.21.02-Biglow	29,782	30 years	(5)%	5.64%	R3	18 years
27	338.21.02-Clearwater	26,173	30 years	(3)%	3.82%	R3	48 years
28	338.21.02-Tucannon	18,009	30 years	(4)%	4.05%	R3	25 years
29	338.21.02-Wheatridge	13,710	30 years	(3)%	3.82%	R3	45 years
30	338.23.00-Biglow	703,070	30 years	(5)%	5.64%	R3	18 years
31	338.23.00-Clearwater	117,020	30 years	(3)%	3.82%	R3	48 years
32	338.23.00-Tucannon	302,518	30 years	(4)%	4.05%	R3	25 years
33	338.23.00-Wheatridge	81,496	30 years	(3)%	3.82%	R3	45 years
34	338.24.00-Biglow	93,363	30 years	(5)%	5.64%	R3	18 years
35	338.24.00-Clearwater	63,339	30 years	(3)%	3.82%	R3	48 years
36	338.24.00-Tucannon	64,900	30 years	(4)%	4.05%	R3	25 years
37	338.24.00-Wheatridge	32,372	30 years	(3)%	3.82%	R3	45 years
38	338.26.00-Biglow	6,846	30 years	(5)%	5.5%	S2.5	18 years
39	338.26.00-Clearwater	81,536	30 years	(3)%	3.83%	S2.5	48 years
40	338.26.00-Tucannon	11,762	30 years	(4)%	4.07%	S2.5	25 years
41	338.26.00-Wheatridge	19,716	30 years	(3)%	3.83%	S2.5	45 years
42	338.27.00-Biglow	12,637	30 years	(5)%	5.5%	S2.5	18 years
43	338.27.00-Clearwater	14,608	30 years	(3)%	3.83%	S2.5	48 years
44	338.27.00-Tucannon	2,762	30 years	(4)%	4.07%	S2.5	25 years
45	338.28.00-Biglow	75,396	30 years	(5)%	5.64%	R3	18 years

46	338.28.00-Clearwater	13,063	30 years	(3)%	3.82%	R3	48 years
47	338.28.00-Tucannon	71,487	30 years	(4)%	4.05%	R3	25 years
48	338.29.00-Biglow	14,665	30 years	(5)%	5.5%	S2.5	18 years
49	338.29.00-Clearwater	846	30 years	(3)%	3.83%	S2.5	48 years
50	338.29.00-Tucannon	765	30 years	(4)%	4.07%	S2.5	25 years
51	338.29.00-Wheatridge	1,095	30 years	(3)%	3.83%	S2.5	45 years
52	338.30.01-SCADA & RTU	5,388	15 years	0%	10.1%	SQ	10 years
53	338.30.02-Biglow	2,938	30 years	(5)%	5.5%	S2.5	18 years
54	338.30.02-Tucannon	12	30 years	(4)%	4.07%	S2.5	25 years
55	338.32.01-Line Equipment	2,489	15 years	0%	8.56%	SQ	12 years
56	338.32.02-Radio, Microwave, Term Eq	3,747	15 years	0%	10.1%	SQ	10 years
57	338.32.03-Mobile Radio Equipment	41	15 years	0%	8.09%	SQ	12 years
58	338.34.00-ARC-Wind Production	14,612				SQ	
59	345.01.00-Computer,Laptop,Servers	284	5 years	0%	37.34%	SQ	3 years
60	345.03.01-Line Equipment	473	15 years	0%	8.56%	SQ	12 years
61	345.03.02-Radio, Microwave, Term Eq	12,330	15 years	0%	10.1%	SQ	10 years
62	345.03.03-Mobile Radio Equipment	211	15 years	0%	8.09%	SQ	12 years
63	351.01.01-SCADA & RTU	5,870	15 years	0%	10.1%	SQ	10 years
64	351.02.03-Computer Software-10 yr	2,305	10 years	0%	10%	SQ	4 years
65	351.03.01-Line Equipment	4,159	15 years	0%	8.56%	SQ	12 years
66	351.03.02-Radio, Microwave, Term Eq	15,913	15 years	0%	10.1%	SQ	10 years
67	351.03.03-Mobile Radio Equipment	233	15 years	0%	8.09%	SQ	12 years
68	351.03.04-Telephone Equipment	49	15 years	0%	12.79%	SQ	8 years
69	363.01.00-Computer,Laptop,Servers	2,452	5 years	0%	37.34%	SQ	3 years
70	363.01.01-SCADA & RTU	10,621	15 years	0%	10.1%	SQ	10 years
71	363.02.02-Computer Software-5 yr	37,739	5 years	0%	20%	SQ	0 years
72	363.02.03-Computer Software-10 yr	34,394	10 years	0%	10%	SQ	6 years

73	363.03.01-Line Equipment	30,984	15 years	0%	8.56%	SQ	12 years
74	363.03.02-Radio, Microwave, Term Eq	44,890	15 years	0%	10.1%	SQ	10 years
75	363.03.03-Mobile Radio Equipment	97	15 years	0%	8.09%	SQ	12 years
76	387.02.00-Structures & Improvements	4,433	70 years	(25)%	2.3%	R2	44 years
77	387.03.00-Constable	108,046	15 years	0%	6.9%	L3	15 years
78	387.03.00-Seaside	263,074	15 years	0%	6.9%	L3	15 years
79	387.03.00-UM-1856 BESS Pilot	36,903	10 years	0%	10%	SQ	9 years
80	387.03.00-Distributed Battery	4,537	15 years	(5)%	13.45%	L3	7 years
81	387.05.00-Constable	11,142	25 years	(5)%	4.29%	S2	25 years
82	387.05.00-Seaside	27,223	25 years	(5)%	4.29%	S2	25 years
83	387.06.00-Constable	11,454	25 years	(5)%	4.29%	S2	25 years
84	387.06.00-Seaside	27,969	25 years	(5)%	4.29%	S2	25 years
85	387.07.00-Constable	9,840	15 years	0%	6.9%	L3	15 years
86	387.07.00-Seaside	24,041	15 years	0%	6.9%	L3	15 years
87	387.08.00-Computer,Laptop,Servers	9,310	5 years	0%	37.34%	SQ	3 years
88	387.08.01-SCADA & RTU	3,818	15 years	0%	10.1%	SQ	10 years
89	387.09.02-Computer Software-5 yr	1,370	5 years	0%	20%	SQ	3 years
90	387.10.02-Radio, Microwave, Term Eq	571	15 years	0%	10.1%	SQ	10 years
91	387.11.00-Misc Energy Storage Equip	21,536	59 years	(20)%	2.92%	S0	34 years
92	397.01.00-Computer,Laptop,Servers	77,919	5 years	0%	37.34%	SQ	3 years
93	397.02.01-Computer Software-3 yr	13,698	3 years	0%	33.33%	SQ	2 years
94	397.02.02-Computer Software-5 yr	449,645	5 years	0%	20%	SQ	2 years
95	397.02.03-Computer Software-10 yr	291,202	10 years	0%	10%	SQ	2 years
96	397.03.01-Line Equipment	3,577	15 years	0%	8.56%	SQ	12 years
97	397.03.02-Radio, Microwave, Term Eq	136,000	15 years	0%	10.1%	SQ	10 years
98	397.03.03-Mobile Radio Equipment	30,081	15 years	0%	8.09%	SQ	12 years

99	397.03.04-Telephone Equipment	612	15 years	0%	12.79%	SQ	8 years
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Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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REGULATORY COMMISSION EXPENSES

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)	EXPENSES INCURRED DURING YEAR	EXPENSES INCURRED DURING YEAR
						CURRENTLY CHARGED TO (f)	CURRENTLY CHARGED TO (g)
1	FERC:			0			
2	FERC Docket ER10-2249		118,095	118,095			
3	FERC matters less than \$25,0000		4,316	4,316			
4	OPUC:		0	0			
5	OPUC Docket LC 80		(144,267)	(144,267)			
6	OPUC Docket UE 430		144,699	144,699			
7	OPUC Docket UM 2111		34,109	34,109			
8	OPUC Docket UE 427		80,525	80,525			
9	OPUC Docket UM 2377		71,232	71,232			
10	(a) OPUC regulatory commission expenses including annual fees and various dockets including: UE 427 Clearwater RAAC, UE 436 2025 Annual Power Cost Update Tariff, UE 435 Request for General Rate Revision, UE 412 Wildfire Mitigation Cost Recovery, UM 2024 Investigation into Long Term Direct Access Programs, UM 2208 Wildfire Mitigation Plan, UM 2211 Implementation of HB 2475		2,120,336	2,120,336			
11	OPUC matters less than \$25,0000		34,253	34,253			
12	Unassigned Non-Doc Matters		(15,142)	(15,142)			
46	TOTAL	0	2,448,156	2,448,156	0		

REGULATORY COMMISSION EXPENSES

Line No.	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO	EXPENSES INCURRED DURING YEAR	AMORTIZED DURING YEAR	AMORTIZED DURING YEAR	AMORTIZED DURING YEAR
	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1					0
2	118,095				0
3	4,316				0
4	0				0
5	(144,267)				0
6	144,699				0
7	34,109				0
8	80,525				0
9	71,232				0
10	2,120,336				0
11	34,253				0
12	(15,142)				0
46	2,448,156	0		0	0

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: RegulatoryCommissionDescription

OPUC regulatory commission expenses including annual fees and various dockets including: UM 2024 Investigation into Long Term Direct Access Programs, UM 2377 and UE 430 -- investigation and tariff changes for New Large Load connections, UE 457 -- 2024 Annual Power Cost Adjustment, UE 458 --2024 Winter Storm Recovery Alternative Rate Recovery, UE 459 -- Alternative Rate Recovery -- Distribution System Plan, UE 455 -- Alternative Rate Recovery -- Seaside Battery, and UM 2000 -- Policy docket with respect to PURPA

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)
1	B(1)	Electric R, D & D Performed Externally		2,466,932
2	B(4)	Electric R, D & D Performed Externally		50,000

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

Line No.	AMOUNTS CHARGED IN CURRENT YEAR	AMOUNTS CHARGED IN CURRENT YEAR	Unamortized Accumulation (g)
	Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	930.2	2,466,932	
2	930.2	50,000	

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DISTRIBUTION OF SALARIES AND WAGES

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	37,594,944		
4	Transmission	8,471,204		
5	Regional Market	0		
5.1	Energy Storage	129,567		
6	Distribution	21,823,232		
7	Customer Accounts	23,618,041		
8	Customer Service and Informational	10,223,211		
9	Sales	0		
10	Administrative and General	109,509,729		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	211,369,928		
12	Maintenance			
13	Production	12,318,443		
14	Transmission	1,459,962		
15	Regional Market	0		
15.1	Energy Storage	381,064		
16	Distribution	28,452,858		
17	Administrative and General	1,484,038		
18	TOTAL Maintenance (Total of lines 13 thru 17)	44,096,365		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	49,913,387		
21	Transmission (Enter Total of lines 4 and 14)	9,931,166		
22	Regional Market (Enter Total of Lines 5 and 15)	0		
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)	510,631		
23	Distribution (Enter Total of lines 6 and 16)	50,276,090		
24	Customer Accounts (Transcribe from line 7)	23,618,041		
25	Customer Service and Informational (Transcribe from line 8)	10,223,211		

DISTRIBUTION OF SALARIES AND WAGES

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
26	Sales (Transcribe from line 9)	0		
27	Administrative and General (Enter Total of lines 10 and 17)	110,993,767		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	255,466,293	28,548,754	284,015,047
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,			

DISTRIBUTION OF SALARIES AND WAGES

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
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)	255,466,293	28,548,754	284,015,047
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	79,659,593	66,950,120	146,609,713
69	Gas Plant			0
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	79,659,593	66,950,120	146,609,713
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,553,054	248,903	1,801,957
74	Gas Plant			0
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,553,054	248,903	1,801,957
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	3,180,756	603,835	3,784,591
79	Co-Owner Shares of Generating Facilities	6,354,780	1,034,627	7,389,407
80	Other	10,813,512	17,618,628	28,432,140
81	Payroll Allocated	115,004,867	(115,004,867)	0
82				

DISTRIBUTION OF SALARIES AND WAGES

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	135,353,915	(95,747,777)	39,606,138
96	TOTAL SALARIES AND WAGES	472,032,855	0	472,032,855

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PURCHASES AND SALES OF ANCILLARY SERVICES

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year	Amount Purchased for the Year	Amount Purchased for the Year
		Usage - Related Billing Determinant Number of Units (b)	Usage - Related Billing Determinant Unit of Measure (c)	Usage - Related Billing Determinant Dollar (d)
1	Scheduling, System Control and Dispatch	348,553	MWH	18,917,153
2	Reactive Supply and Voltage			
3	Regulation and Frequency Response			
4	Energy Imbalance	182,650	MWH	5,983,122
5	Operating Reserve - Spinning			
6	Operating Reserve - Supplement			
7	Other			
8	Total (Lines 1 thru 7)	531,203		24,900,275

PURCHASES AND SALES OF ANCILLARY SERVICES

Line No.	Amount Sold for the Year	Amount Sold for the Year	Amount Sold for the Year
	Usage - Related Billing Determinant Number of Units (e)	Usage - Related Billing Determinant Unit of Measure (f)	Usage - Related Billing Determinant Dollars (g)
1	1,221,144	MWH	990,002
2	10,329	MWH	123,810
3	4,108	MWH	361,485
4	39,504	MWH	1,382,397
5	131,733	MW	417,942
6	131,733	MW	417,942
7			
8	1,538,551		3,693,578

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FOOTNOTE DATA			

<p>(a) Concept: AncillaryServicesPurchasedNumberOfUnits</p>
<p>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. 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.</p>
<p>(b) Concept: AncillaryServicesPurchasedAmount</p>
<p>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. 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.</p>
<p>(c) Concept: AncillaryServicesSoldNumberOfUnits</p>
<p>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. 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.</p>
<p>(d) Concept: AncillaryServicesSoldAmount</p>
<p>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. 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.</p>
<p>(e) Concept: AncillaryServicesSoldNumberOfUnits</p>
<p>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.</p>

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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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	4,898	7	19	3,091	256	2,561	80	3,502	68
2	February	4,805	13	13	3,471	318	2,561	76	3,502	36
3	March	4,793	20	11	2,690	335	2,561	66	4,240	188
4	Total for Quarter 1				9,252	909	7,683	222	11,244	292
5	April	4,460	3	8	2,628	323	2,561	74	4,102	785
6	May	4,317	13	22	2,270	309	2,561	51	4,240	110
7	June	5,155	9	16	3,517	387	2,561	82	3,902	131
8	Total for Quarter 2				8,415	1,019	7,683	207	12,244	1,026
9	July	5,356	16	17	3,724	387	2,561	95	3,518	550
10	August	5,442	11	18	3,929	398	2,561	89	3,713	109
11	September	4,889	4	18	3,580	382	2,561	80	3,902	138
12	Total for Quarter 3				11,233	1,167	7,683	264	11,133	797
13	October	4,394	29	8	2,541	330	2,561	59	3,902	279
14	November	4,617	24	18	2,934	321	2,561	65	3,902	179
15	December	5,126	22	10	2,787	320	2,561	73	3,952	665
16	Total for Quarter 4				8,262	971	7,683	197	11,756	1,123
17	Total				37,162	4,066	30,732	890	46,377	3,238

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ELECTRIC ENERGY ACCOUNT

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)	19,968,167
3	Steam	1,935,857	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	9,856,351
5	Hydro-Conventional	1,204,562	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	27,395
6.1	Solar	1,949	27	Total Energy Losses	896,443
6.2	Wind	2,735,746	27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	30,748,356
7	Other	10,815,308			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	16,693,422			
10	Purchases (other than for Energy Storage)	14,044,409			
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	5,056,600			
17	Delivered	5,046,075			
18	Net Transmission for Other (Line 16 minus line 17)	10,525			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	30,748,356			

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MONTHLY PEAKS AND OUTPUT						
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	2,720,323	682,120	3,685	30	8
30	February	2,403,479	635,705	3,879	13	11
31	March	2,450,766	708,322	3,176	14	9
32	April	2,274,912	772,721	2,998	1	8
33	May	2,391,630	855,224	3,074	28	19
34	June	2,483,774	880,996	4,052	9	18
35	July	2,913,239	1,071,080	4,114	16	19
36	August	2,887,954	989,734	4,385	12	19
37	September	2,558,012	923,848	3,948	4	18
38	October	2,494,356	831,310	3,001	30	9
39	November	2,463,729	745,172	3,294	25	18
40	December	2,706,182	862,489	3,466	29	18
41	Total	30,748,356	9,958,721			

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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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 of 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: Plant Name: Beaver	Plant Name: Plant Name: Carty	Plant Name: ^(a) Plant Name: Colstrip	Plant Name: Plant Name: Coyote Springs	Plant Name: Plant Name: Port Westward 1	Plant Name: Plant Name: Port Westward 2
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas & Steam Turbine	Gas & Steam Turbine	Steam	Gas & Steam Turbine	Gas & Steam Turbine	Reciprocating 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	503	311	296	483	225
6	Net Peak Demand on Plant - MW (60 minutes)	514	472	0	279	432	224
7	Plant Hours Connected to Load	9,927	8,003	0	8,217	8,344	6,643
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0	0
9	When Not Limited by Condenser Water	533	0	0	270	421	225
10	When Limited by Condenser Water	0	0	0	0	0	0
11	Average Number of Employees	42	34	0	31	33	0
12	Net Generation, Exclusive of Plant Use - kWh	1,910,519,000	3,136,926,000	1,935,857,000	2,001,236,000	3,259,566,000	1,116,184,000

13	Cost of Plant: Land and Land Rights	24,473	0	3,328,862	0	24,473	0
14	Structures and Improvements	38,043,496	95,911,049	116,250,719	11,768,619	43,222,799	42,471,958
15	Equipment Costs	367,826,733	446,777,542	378,425,157	199,391,313	252,713,683	280,293,573
16	Asset Retirement Costs	2,941,318	10,434,861	28,988,053	113,193	231,072	647,461
17	Total Cost (10-23)	408,836,020	553,123,452	526,992,791	211,273,125	296,192,027	323,412,992
18	Cost per KW of Installed Capacity (line 17/5) Including	717.2562	1,099.649	1,694.5106	713.7606	613.234	1,437.3911
19	Production Expenses: Oper, Supv, & Engr	394,216	599,544	75,405	209,881	528,104	213,255
20	Fuel	50,237,436	51,105,007	45,578,906	27,135,889	66,110,182	27,244,597
21	Coolants and Water (Nuclear Plants Only)	0	0	0	0	0	0
22	Steam Expenses	0	0	1,968,474	0	0	0
23	Steam From Other Sources	0	0	0	0	0	0
24	Steam Transferred (Cr)	0	0	0	0	0	0
25	Electric Expenses	3,626,269	3,629,733	0	3,203,418	3,477,799	2,260,021
26	Misc Steam (or Nuclear) Power Expenses	644,412	2,341,489	18,704,582	588,634	873,248	152,984
27	Rents	216,590	0	0	80,866	28,586	33,347
28	Allowances	0	0	0	0	0	0
29	Maintenance Supervision and Engineering	1,134,932	28,193	612,936	147,323	108,167	78,023
30	Maintenance of Structures	72,325	2,930	1,228,531	81,306	160,487	11,930
31	Maintenance of Boiler (or reactor) Plant	0	0	12,168,253	0	0	0
32	Maintenance of Electric Plant	7,239,686	10,433,209	2,429,103	3,841,660	8,986,135	5,512,354
33	Maintenance of Misc Steam (or Nuclear) Plant	207,922	201,726	812,820	51,224	89,293	195,939
34	Total Production Expenses	63,773,788	68,341,831	83,579,010	35,340,201	80,362,001	35,702,450
35	Expenses per Net kWh	0.0334	0.0218	0.0432	0.0177	0.0247	0.032
35	Plant Name	Plant Name: Beaver	Plant Name: Beaver	Plant Name: Carty	Plant Name: Coyote Springs	Plant Name: Port Westward 1	Plant Name: 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	18,044,195	0	21,646,793	14,263,043	22,680,876	9,329,952

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	3.463	0	1.466	1.404	2.754	2.872
41	Average Cost of Fuel per Unit Burned	2.647	0	2.361	1.903	2.915	2.92
42	Average Cost of Fuel Burned per Million BTU	2.597	0	2.316	1.867	2.86	2.865
43	Average Cost of Fuel Burned per kWh Net Gen	0.026	0	0.016	0.014	0.02	0.024
44	Average BTU per kWh Net Generation	9,627.58	0	7,034.29	7,265.155	7,093.018	8,520.687

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ 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, in 2025 there was no 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, in 2025 there was no oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

Name of Respondent: Portland General Electric Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
Renewable Generating Plant Statistics					
<p>1. Report data for plant in Service only. 2. Report in this page renewable plants of 10,000 Kw or more. 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. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.</p>					
Line No.	Item (a)	Plant Name: Biglow	Plant Name: Clearwater	Plant Name: Tucannon	Plant Name: Wheatridge
1	Kind of Plant (Solar, Wind, Biomass, etc.)	Wind	Wind	Wind	Wind
2	Type of Constr (PV Tracking, Offshore, Boiler, etc)	Onshore	Onshore	Onshore	Onshore
3	Year Originally Constructed	2007	2024	2014	2020
4	Year Last Unit was Installed	2010	2024	2014	2020
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	449.7	208.2	266.8	100.1
6	Net Peak Demand on Plant - MW (60 minutes)	417	300	261	100
7	Plant Hours Connected to Load	6,273	8,277	6,505	6,642
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0
9	Net Generation, Exclusive of Plant Use - KWh	896,260,000	821,721,000	739,089,000	252,376,000
10	Cost of Plant: Land and Land Rights	0	0	0	0
11	Structures and Improvements	64,272,458	123,549,360	36,896,912	17,151,144
12	Solar Panels, Wind Turbines and Generators	796,433,119	180,358,696	367,418,040	113,868,625
13	Fuel Holders	0	0	0	0
14	Boilers	0	0	0	0
15	Collector System	6,846,156	81,536,251	11,761,667	19,715,527
16	Generator Step-up Transformers (GSU)	12,636,513	14,607,607	2,761,597	0
17	Inverters	75,395,753	13,062,611	71,487,146	0
18	Other Accessory Electrical Equipment	14,664,985	845,959	765,445	1,094,862
19	Computer Hardware	4,340,982	1,492,871	940,187	1,564,090
20	Computer Software	0	0	0	0
21	Communication Equipment	994,605	0	5,283,269	0
22	Miscellaneous Power Plant Equipment	0	0	0	0

23	Asset Retirement Costs	1,836,510	3,637,311	6,371,939	2,766,485
24	Total Cost (10-23)	977,421,081	419,090,666	503,686,202	156,160,733
25	Cost per KW of Installed Capacity (line 24/5) Including	2,173.4958	2,012.9235	1,887.8793	1,560.0473
26	Production Expenses: Oper, Supv, & Engr	1,460,459	0	2,310,362	3,730
27	Generation and Other Plant Operating Expenses	523,929	203,834	69,424	18,825
28	Fuel	0	0	0	0
29	Steam Expenses	0	0	0	0
30	Electric Expenses	0	0	0	0
31	Misc Steam Power Expenses	0	0	0	0
32	Rents	2,620	0	49,135	0
33	Environmental Credits	0	0	0	0
34	Maintenance Supervision and Engineering	123,917	0	14,459	0
35	Maintenance of Structures and Equipment	815,421	3,393	298,388	510,658
36	Maintenance of Boiler Plant	0	0	0	0
37	Maintenance of Electric Plant	0	0	0	0
38	Maintenance of Computer Hardware	2,067	13	669	2
39	Maintenance of Computer Software	232,994	26,156	91,352	5,324
40	Maintenance of Communication Equipment	24,708	187	9,074	29
41	Maintenance of Misc Plant	8,426,828	3,507,240	3,883,351	2,672,471
42	Total Production Expenses	11,612,943	3,740,823	6,726,214	3,211,039
43	Expenses per Net KWh	0.013	0.0046	0.0091	0.0127

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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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.

Hydroelectric Generating Plant Statistics

Line No.	Item (a)	FERC Licensed Project No. 2195	FERC Licensed Project No. 2195	FERC Licensed Project No. 2195
		Plant Name: Faraday	Plant Name: North Fork	Plant Name: Oak Grove
1	Kind of Plant (Run-of-River or Storage)	Run-of-River;Storage	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional; Outdoor	Outdoor	Conventional
3	Year Originally Constructed	1907	1958	1924
4	Year Last Unit was Installed	2023	1958	1931
5	Total installed cap (Gen name plate Rating in MW)	50	62.1	51
6	Net Peak Demand on Plant-Megawatts (60 minutes)	44	100	37
7	Plant Hours Connect to Load	8,758	8,760	8,409
8	Net Plant Capability (in megawatts)			
9	(a) Under Most Favorable Oper Conditions	46	56	42
10	(b) Under the Most Adverse Oper Conditions	5	7	19
11	Average Number of Employees	58	0	0
12	Net Generation, Exclusive of Plant Use - kWh	134,201,000	165,560,000	156,804,000
13	Cost of Plant			
14	Land and Land Rights	33,434	377,100	9,457
15	Structures and Improvements	149,929,345	9,396,041	22,252,281
16	Reservoirs, Dams, and Waterways	65,475,244	85,253,319	32,425,726
17	Equipment Costs	47,047,910	22,811,354	36,098,528
18	Roads, Railroads, and Bridges	2,087,835	2,837,601	6,802,043
19	Asset Retirement Costs	90	6	2,122
20	Total Cost (10-23)	264,573,858	120,675,421	97,590,157
21	Cost per KW of Installed Capacity (line 20 / 5)	5,291.4772	1,943.2435	1,913.5325

Hydroelectric Generating Plant Statistics

Line No.	Item (a)	FERC Licensed Project No. 2195	FERC Licensed Project No. 2195	FERC Licensed Project No. 2195
		Plant Name: Faraday	Plant Name: North Fork	Plant Name: Oak Grove
22	Production Expenses			
23	Operation Supervision and Engineering	264,715	85,384	200,571
24	Water for Power	366,594	76,926	96,461
25	Hydraulic Expenses	1,594,839	527,179	1,660,225
26	Electric Expenses	950,809	238,365	57,918
27	Misc Hydraulic Power Generation Expenses	838,251	398,645	101,609
28	Rents	202,799	125,691	1,106,122
29	Maintenance Supervision and Engineering	492,033	11,426	2,490
30	Maintenance of Structures	0	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	80,359	64,885	372,396
32	Maintenance of Electric Plant	1,567,541	336,783	639,438
33	Maintenance of Misc Hydraulic Plant	1,347,375	307,000	214,832
34	Total Production Expenses (total 23 thru 33)	7,705,315	2,172,284	4,452,062
35	Expenses per net kWh	0.0574	0.0131	0.0284

Hydroelectric Generating Plant Statistics

Line No.	FERC Licensed Project No. 2030	FERC Licensed Project No. 2030	FERC Licensed Project No. 2195	FERC Licensed Project No. 2030
	Plant Name: <small>(a)</small> Pelton	Plant Name: <small>(b)</small> Pelton (PGE%)	Plant Name: River Mill	Plant Name: <small>(c)</small> Round Butte
1	Storage	Storage	Run-of River	Storage
2	Outdoor	Outdoor	Conventional	Conventional
3	1957	1957	1911	1964
4	1958	1958	1952	1964
5	109.8	54.9	20.7	372.5
6	109	0	25	309
7	8,683	0	7,114	7,069
8				
9	122	0	25	373
10	60	0	4	192
11	<small>(a)</small> 0	0	0	<small>(c)</small> 47
12	397,076,585	198,578,000	77,791,000	771,355,729
13				
14	3,681,653	1,841,302	86,732	3,699,286
15	10,545,595	5,297,506	7,497,936	18,801,763
16	15,511,814	8,016,063	62,191,594	174,886,274
17	42,099,597	21,541,251	20,103,037	80,052,876
18	6,437,446	3,514,808	475,899	2,568,063
19	52	52	64	164
20	78,276,157	40,210,982	90,355,262	280,008,426
21	712.8976	732.4405	4,364.9885	751.7005
22				
23	286,382	72,987	98,426	662,234
24	260,326	98,805	63,664	457,688
25	2,653,412	1,280,137	528,898	3,454,274
26	451,648	219,472	139	581,048
27	159,135	54,313	7,941	310,357
28	16,387	4,531	0	36,319
29	2,986	1,591	0	3,244
30	0	0	3,018	0
31	162,066	35,298	26,715	402,386

Hydroelectric Generating Plant Statistics

Line No.	FERC Licensed Project No. 2030	FERC Licensed Project No. 2030	FERC Licensed Project No. 2195	FERC Licensed Project No. 2030
	Plant Name: <small>(a)</small> Pelton	Plant Name: <small>(b)</small> Pelton (PGE%)	Plant Name: River Mill	Plant Name: <small>(c)</small> Round Butte
32	951,792	432,050	445,976	1,361,437
33	212,217	74,552	214,644	409,719
34	5,156,351	2,273,736	1,389,421	7,678,706
35	0.013	0.0115	0.0179	0.01

Hydroelectric Generating Plant Statistics

Line No.	FERC Licensed Project No. 2030 Plant Name: <small>(d)</small> Round Butte (PGE%)	FERC Licensed Project No. 2233 Plant Name: Sullivan
1	Storage	Run-of River
2	Conventional	Conventional
3	1964	1895
4	1964	1953
5	186.3	16.9
6	0	33
7	0	7,935
8		
9	0	18
10	0	7
11	0	2
12	385,755,000	85,873,000
13		
14	1,891,263	572,077
15	9,447,633	17,935,635
16	89,945,439	31,486,624
17	180,940,952	25,195,284
18	1,380,273	0
19	164	2,630
20	283,605,724	75,192,250
21	1,522.3066	4,449.2456
22		
23	401,418	91,651
24	260,274	52,709
25	1,775,827	246,300
26	297,278	52,690
27	182,242	38,168
28	21,828	0
29	1,539	2,508
30	0	0
31	247,447	371,599

Hydroelectric Generating Plant Statistics

Line No.	FERC Licensed Project No. 2030 Plant Name: <small>(d)</small> Round Butte (PGE%)	FERC Licensed Project No. 2233 Plant Name: Sullivan
32	726,197	306,523
33	241,461	74,298
34	4,155,511	1,236,446
35	0.0108	0.0144

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

<p>(a) Concept: PlantName</p>
<p>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.</p>
<p>(b) Concept: PlantName</p>
<p>Jointly owned. Reported here are respondents 50.01% share of installed capacity, cost of plant, net generation and production expenses.</p>
<p>(c) Concept: PlantName</p>
<p>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.</p>
<p>(d) Concept: PlantName</p>
<p>Jointly owned. Reported here are respondents 50.01% share of installed capacity, cost of plant, net generation and production expenses.</p>
<p>(e) Concept: PlantAverageNumberOfEmployees</p>
<p>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.</p>
<p>(f) Concept: PlantAverageNumberOfEmployees</p>
<p>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.</p>

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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GENERATING PLANT STATISTICS (Small Plants)

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)
1	Oregon Military Dept/Anderson Readiness Center	2001	1.6	1.5	26	192,125
2	US Bank Corp Columbia Center	2001	6.4	6.2	39	499,118
3	Portland State University	2004	2.8	2.8	20	261,802
4	Oregon Military Joint Forces HQ	2005	1.6	1.6	13	1,648,709
5	Stimson Lumber	2005	0.57	0.51	3	159,546
6	Flexential (Formerly ViaWest/Fortix)	2005	14	12.4	157	6,354,946
7	Skyline	2005	2	1.8	50	1,225,359
8	NCCWC Filter Plant	2005	2	1.8	23	933,461
9	PCC Structural	2005	1	0.9	7	113,874
10	Providence Portland Medical Center	2005	6	5.4	83	2,881,007
11	Salem Hospital	2006	8	7.2	108	269,108
12	Sunrise Water Authority Pump Station	2006	1.25	1.125	8	687,432
13	Providence Newberg Hospital	2006	1.5	1.35	16	1,182,547
14	H5 (Formerly vXchnge/Sungard DSG)	2006	2	1.8	7	1,691,253
15	Kaiser Sunnyside Hospital	2007	4.5	4.05	56	2,379,693
16	Newberg Waste Water Treatment Plant	2008	2	1.8	32	815,592
17	Xerox Corp	2007	4	3.6	38	1,590,909
18	Newberg Water Treatment Plant	2007	1	0.9	27	93,985
19	Oregon Dept of Admin Serv - Data Center	2010	3.86	3.47	40	2,571,639
20	Amazon (Formerly Panasonic/Sanyo)	2010	1	0.7	6	666,960
21	Sysco Foods	2010	2	1.8	16	1,180,486
22	Clackamas Intertie 2	2012	0.6	0.54	15	729,397
23	DAW - Dawson Creek	2012	0.8	0.72	0	111,532
24	Kaiser Westside Hospital	2012	4	3.6	61	2,244,105
25	North Plains Pump Station	2012	0.8	0.72	0	68,958
26	Oak Lodge Sanitary District	2012	2	1.8	63	1,342,121

GENERATING PLANT STATISTICS (Small Plants)

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)
27	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.5	1.25	9	891,119
28	Oregon State Hospital	2012	4	3.6	53	1,391,121
29	Portland Service Center	2012	0.5	0.45	10	338,681
30	Sandy Highschool	2012	1.25	1.125	31	954,165
31	TATA Communications - Hillsboro	2012	4.5	4.05	0	328,979
32	Tri-City Wastewater Treatment Plant	2012	2.5	2.25	44	177,520
33	TATA Communications - Portland	2013	6	5.4	0	612,983
34	CRAND - City of Hillsboro - Crandall Reservoir	2013	0.8	0.72	0	121,679
35	East County Courts	2013	1.5	1.35	13	1,462,943
36	City of Portland-Columbia Blvd WWTP	2013	1	0.9	17	178,060
37	US Foods (Formerly Food Services of America)	2013	2	1.8	42	999,515
38	Avery DSG	2014	0.8	0.72	21	263,782
39	Carver (Readiness Center) DSG	2014	2	1.8	36	818,635
40	Juvenile Justice Center	2014	0.75	0.675	5	797,758
41	Clackamas River Water	2014	2	1.8	36	1,159,930
42	Joint Water Commission	2015	5	4.5	125	2,810,736
43	McLane Foodservice	2016	1.5	1.35	29	940,072
44	Flexential Brookwood (Formerly ViaWest Brookwood)	2016	16.25	14.63	142	582,945
45	World Trade Center	2017	3.2	2.88	31	1,021,168
46	Washington County Jail	2017	1.5	1.35	13	1,480,887
47	OHSU - Vaccine Gene Therapy Institute	2017	1.5	1.25	0	366,768
48	OHSU - Center for Health & Healing	2018	3	2.7	43	3,531,565
49	OHSU - Knight Cancer Research Building	2018	2	1.8	17	1,639,659
50	Hattan Road Pump Station - HRPS	2021	1	0.9	0	212,306
51	Beaverton Public Service Center	2021	1	0.9	0	523,446
52	Kellogg Creek WWTP	2020	1.5	1.35	34	284,962
53	Solar	2012	3.019	3.019	1,950	1,324,428

GENERATING PLANT STATISTICS (Small Plants)

Line No.	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses	Production Expenses	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
			Fuel Production Expenses (i)	Maintenance Production Expenses (j)		
1	120,078	0	11,976	21,063	diesel-low	2,267
2	77,987	0	73,349	100,957	diesel-low	2,005
3	93,501	0	0	51,374	diesel-low	2,109
4	1,030,443	0	0	40,169	diesel-low	2,109
5	279,905	0	0	21,937	diesel-low	2,109
6	453,925	0	51,313	204,128	diesel-low	2,212
7	612,680	0	9,582	9,160	diesel-low	2,509
8	466,731	0	5,872	30,339	diesel-low	2,165
9	113,874	0	2,404	32,751	diesel-low	2,467
10	480,168	0	21,251	31,033	diesel-low	1,886
11	33,639	0	0	58,435	diesel-low	2,109
12	549,946	0	3,916	7,625	diesel-low	2,165
13	788,365	0	9,840	48,420	diesel-low	2,155
14	845,627	0	2,795	25,505	diesel-low	1,828
15	528,821	0	0	27,544	diesel-low	2,109
16	407,796	0	6,733	36,892	diesel-low	2,108
17	397,727	0	5,621	16,737	diesel-low	2,121
18	93,985	0	7,043	39,361	diesel-low	2,597
19	666,228	0	0	67,092	diesel-low	2,109
20	666,960	0	1,471	14,691	diesel-low	2,305
21	590,243	0	5,790	21,527	diesel-low	2,416
22	1,215,662	0	3,286	6,241	diesel-low	1,400
23	139,415	0	0	0	diesel-low	0
24	561,026	0	22,282	19,582	diesel-low	2,004
25	86,198	0	0	0	diesel-low	0
26	671,061	0	11,018	45,419	diesel-low	2,207
27	594,079	0	2,917	10,407	diesel-low	2,311
28	347,780	0	20,504	48,413	diesel-low	1,777
29	677,362	0	0	15,419	diesel-low	2,109
30	763,332	0	8,815	7,424	diesel-low	2,307
31	73,106	0	0	33,301	diesel-low	0

GENERATING PLANT STATISTICS (Small Plants)

Line No.	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses	Production Expenses	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
			Fuel Production Expenses (i)	Maintenance Production Expenses (j)		
32	71,008	0	9,659	10,266	diesel-low	2,087
33	102,164	0	0	807	diesel-low	0
34	152,099	0	0	1,429	diesel-low	2,109
35	975,295	0	0	15,451	diesel-low	2,109
36	178,060	0	2,910	6,546	diesel-low	2,483
37	499,758	0	7,865	9,999	diesel-low	2,262
38	329,728	0	0	14,104	diesel-low	2,109
39	409,318	0	9,923	32,151	diesel-low	2,456
40	1,063,677	0	1,247	23,126	diesel-low	2,243
41	579,965	0	8,808	22,580	diesel-low	2,330
42	562,147	0	30,326	11,539	diesel-low	2,066
43	626,715	0	6,401	33,927	diesel-low	2,045
44	35,874	0	0	150,631	diesel-low	2,109
45	319,115	0	6,543	84,022	diesel-low	2,353
46	987,258	0	0	47,285	diesel-low	2,109
47	244,512	0	0	1,439	diesel-low	0
48	1,177,188	0	16,422	19,806	diesel-low	2,108
49	819,830	0	7,078	7,893	diesel-low	2,215
50	212,306	0	0	40,219	diesel-low	2,109
51	523,446	0	0	5,863	diesel-low	2,109
52	189,975	0	6,519	50,954	diesel-low	2,420
53	438,698	24,523	0	26,468	solar	0

GENERATING PLANT STATISTICS (Small Plants)

Line No.	Generation Type (m)
1	Other
2	Other
3	Other
4	Other
5	Other
6	Other
7	Other
8	Other
9	Other
10	Other
11	Other
12	Other
13	Other
14	Other
15	Other
16	Other
17	Other
18	Other
19	Other
20	Other
21	Other
22	Other
23	Other
24	Other
25	Other
26	Other
27	Other
28	Other
29	Other
30	Other
31	Other
32	Other
33	Other

GENERATING PLANT STATISTICS (Small Plants)

Line No.	Generation Type (m)
34	Other
35	Other
36	Other
37	Other
38	Other
39	Other
40	Other
41	Other
42	Other
43	Other
44	Other
45	Other
46	Other
47	Other
48	Other
49	Other
50	Other
51	Other
52	Other
53	Other

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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ENERGY STORAGE OPERATIONS (Large Plants)

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)
1	Coffee Creek Energy Storage	Washington County, OR	9,725	9,725	1,232	8,558	821,585
2							
3	Constable Battery Energy Storage	Washington County, OR	82,089	82,089	10,846	72,238	6,935,021
4							
5							
6	Seaside Battery Energy Storage	Multnomah County, OR	125,364	125,364	17,340	110,320	10,590,969
7	^(a) Wheatridge Battery Lease	Morrow County, OR	0	0	0	0	0
8	Sundial Operating Lease	Multnomah County, OR	267,295	267,295	33,183	235,220	22,581,546
35	TOTAL		484,473	484,473	62,601	^(b) 426,336	^(c) 40,929,121

ENERGY STORAGE OPERATIONS (Large Plants)

Line No.	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
1	424,792			387.03.00- 387.11.00	28,174,535
2					
3	3,711,729			387.01.00- 387.11.00	155,518,485
4					
5					
6	5,550,222			387.01.00- 387.11.00	386,348,725
7	0			387.03.00	29,042,602
8	12,327,731			387.03.00	295,342,292
35	22,014,474	0	0		894,426,639

FOOTNOTE DATA

(a) Concept: EnergyStorageProjectNameLargePlants

Energy received pursuant to this Power Purchase Agreement (PPA) comprises generation sourced from the associated solar facility, as well as energy discharged from the battery storage system. The battery storage system is charged exclusively through the output of the aforementioned solar facility.

(b) Concept: EnergySold

PGE's large battery fleet is on-system. 88% of the discharge is assumed to meet system on peak needs (reported here) where the remaining 12% is assumed to be used for merchant ancillary services.

(c) Concept: RevenuesFromEnergyStorageOperations

PGE is unable to discern how much of the discharge for energy arbitrage was retail load serving versus sold to wholesale markets. As such, a weighted average method was used to develop total sales value for this page contemplating 2025 customer rates and wholesale MidC prices. The implied sales were recognized in FERC accounts: 447, 440, 442 and 444.

(d) Concept: PowerPurchasedForStorageOperationsLargePlants

PGE is unable to discern what transaction explicitly was used to charge its large on-system battery fleet. For this page, we assume it was charged using purchased power at the MidC day ahead off-peak price.

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ENERGY STORAGE OPERATIONS (Small Plants)

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses		Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)			
1	Beaverton Public Safety Center	Washington County, OR	1308628	0	11,132	0	0	0
2								
3								
4	Port Westward 2	Columbia County, OR	6332259		40,823			
5	Anderson Readiness Center	Marion County, OR	1658159		10,735			
6								
7								
8								
36	TOTAL		9,299,046	0	62,690	0	0	0

ENERGY STORAGE OPERATIONS (Small Plants)

Line No.	Plant Operating Expenses	Plant Operating Expenses	Plant Operating Expenses	Plant Operating Expenses	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Operations (Excluding Fuel used in Storage Operations) (d)				
1	Beaverton Public Safety Center	Washington County, OR	1308628	0	11,132	0	0	0
2								
3								
4	Port Westward 2	Columbia County, OR	6332259		40,823			
5	Anderson Readiness Center	Marion County, OR	1658159		10,735			
6								
7								
8								
36	TOTAL		9,299,046	0	62,690	0	0	0

ENERGY STORAGE OPERATIONS (Small Plants)

Plant Operating Expenses								
Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1	Beaverton Public Safety Center	Washington County, OR	1308628	0	11,132	0	0	0
2								
3								
4	Port Westward 2	Columbia County, OR	6332259		40,823			
5	Anderson Readiness Center	Marion County, OR	1658159		10,735			
6								
7								
8								
36	TOTAL		9,299,046	0	62,690	0	0	0

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION	DESIGNATION	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)	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)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)	Number of Circuits
	From (a)	To (b)	Operating (c)	Designated (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	500KV LINES							
2	^(a) BOARDMAN	GRASSLAND	500	500	ST. TOWER	0.94		1
3	^(b) BROADVIEW SWITCHYARD	TOWNSEND 'A'	500	500	ST. TOWER	133.4		1
4	^(c) BROADVIEW SWITCHYARD	TOWNSEND 'B'	500	500	ST. TOWER	133.4		1
5	CARTY	GRASSLAND	500	500	ST. TOWER	0.75		1
6	^(d) COLSTRIP SWITCHYARD	BROADVIEW 'A'	500	500	ST. TOWER	112.7		1
7	^(e) COLSTRIP SWITCHYARD	BROADVIEW 'B'	500	500	ST. TOWER	115.9		1
8	^(f) COYOTE SPRINGS	SLATT BPA	500	500				
9	GRASSLAND	SLATT BPA	500	500	ST. TOWER	16.73		1
10	GRIZZLY BPA	MALIN BPA #2	500	500	ST. TOWER	178.5		1
11	GRIZZLY BPA	ROUND BUTTE	500	500	ST. TOWER	15.6		1
12	^(g) JOHN DAY	GRIZZLY '1'	500	500				1
13	^(h) JOHN DAY	GRIZZLY '2'	500	500				1
14	TOTAL 500KV LINES							
15	230 KV LINES							
16	BEAVER	PORT WESTWARD	230	230	H-WOOD	0.41		1
17	BETHEL	McLOUGHLIN	230	230	H-WOOD	35.52		1
18	BETHEL	ROUND BUTTE	230	230	H-WOOD/ST. TOWER	98.68		1
19	BETHEL	SANTIAM BPA	230	230	H-WOOD	3.64		1
20	⁽ⁱ⁾ BIG EDDY BPA	McLOUGHLIN	230	230	H-WOOD	0.91		1

TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION	DESIGNATION	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)	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)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)	Number of Circuits
	From (a)	To (b)	Operating (c)	Designated (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
21	(u) BIGLOW CANYON WF	JOHN DAY #1 BPA	230	230				1
22	BLUE LAKE	GRESHAM	230	230	ST. TOWER	5.92		2
23	BLUE LAKE	TROUTDALE BPA #1	230	230	ST. MONOP/ST. TOWER	1.45		1
24	BLUE LAKE	TROUTDALE BPA #2	230	230	ST. MONOP/ST. TOWER	0.15	1.34	2
25	(k) CARLTON BPA	SHERWOOD	230	230	ST. TOWER	8.95		2
26	CARVER	GRESHAM #1	230	230	H-WOOD	7.33		1
27	CARVER	McLOUGHLIN #1	230	230	H-WOOD/ST. MONOP	4.87		1
28	CARVER	McLOUGHLIN #2	230	230	ST. MONOP	4.88		1
29	CENTRAL FERRY BPA	MULLAN (TUCANNON WF)	230	230	H-WOOD	20.62		1
30	DALREED PACW	(g) CARTY	230	230	H-WOOD	16.76		1
31	EVERGREEN	HORIZON	230	230	Tubular Steel Pole	1.86		2
32	EVERGREEN	ST. MARYS-TROJAN	230	230	Steel Pole/Lattice Towers	14.03	32.6	2
33	(u) GRESHAM	TROUTDALE PACW #1	230	230	H-WOOD	0.43		1
34	GRESHAM	TROUTDALE PACW #2	230	230	ST. TOWER	0.33		1
35	HARBORTON	RIVERGATE #1	230	230	ST. TOWER/H-WOOD	1.7		1
36	HARBORTON	TROJAN #1	230	230	ST TOWER	33.6		2
37	HORIZON	KEELER BPA#1	230	230	ST. MONOP	1.47		2
38	HORIZON	KEELER BPA#2	230	230	ST. MONOP	1.79		2
39	(m) KEELER BPA	RIVERGATE	230	230	ST. TOWER	0.08		2
40	KEELER BPA	ST. MARYS	230	230	H-WOOD/ST. TOWER	6.62		2

TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION	DESIGNATION	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)	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)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)	Number of Circuits
	From (a)	To (b)	Operating (c)	Designated (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
41	McLOUGHLIN	PEARL BPA - SHERWOOD	230	230	ST. TOWER/ST. MONOP	16.38	4.7	2
42	MURRAYHILL	SHERWOOD #1	230	230	ST. TOWER	5.58		2
43	MURRAYHILL	SHERWOOD #2	230	230	ST. TOWER		5.55	2
44	MURRAYHILL	ST. MARYS	230	230	ST. TOWER	5.2		2
45	(a) PEARL BPA	SHERWOOD#1	230	230	ST. MONOP/ST. TOWER/H-WOOD	0	0.16	1
46	(a) PELTON	ROUND BUTTE	230	230	H-WOOD	7.87		1
47	PORT WESTWARD	TROJAN #1	230	230	H-WOOD/ST. MONOP	18.76		1
48	PORT WESTWARD	TROJAN #2	230	230	H-WOOD/ST. MONOP	9.28	9.48	2
49	REDMOND BPA	ROUND BUTTE	230	230	H-WOOD	23.81		1
50	(a) RIVERGATE	ROSS BPA	230	230	ST. TOWER	0.09		2
51	RIVERGATE	SEASIDE	230	230	Steel Poles	0.64		1
52	ROUND BUTTE	GENERATOR #1	230	230	ST. TOWER			1
53	ROUND BUTTE	GENERATOR #2	230	230	ST. TOWER			1
54	ROUND BUTTE	GENERATOR #3	230	230	ST. TOWER			1
55	TOTAL 230KV LINES							
56	ALL 115KV LINES					463.5		
57	ALL 57KV LINES					346		
36	TOTAL					1,877.03	53.83	66

TRANSMISSION LINE STATISTICS

Line No.	Size of Conductor and Material (i)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	EXPENSES, EXCEPT DEPRECIATION AND TAXES	EXPENSES, EXCEPT DEPRECIATION AND TAXES	EXPENSES, EXCEPT DEPRECIATION AND TAXES	EXPENSES, EXCEPT DEPRECIATION AND TAXES
		Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1				0				0
2	2-1780 ACSR			0				0
3				0				0
4				0				0
5	2-1780 ACSR			0				0
6				0				0
7				0				0
8				0				0
9	2-1780 ACSR			0				0
10	2-1780 ACSR			0				0
11	2-1780 ACSR			0				0
12				0				0
13				0				0
14		1,526,610	86,743,180	88,269,790	2,522,454	907,270	2,005,682	5,435,406
15				0				0
16	2156 ACSS			0				0
17	1272 AAC			0				0
18	1272 AAC			0				0
19	795 ACSR			0				0
20	1780 ACSR			0				0
21	2-1272 AAC			0				0
22	1272 ACSS			0				0
23	1272 ACSS			0				0
24	1272 ACSS			0				0
25	1272 ACSR			0				0
26	1272 AAC			0				0
27	1272 AAC			0				0
28	1272 ACSS			0				0
29	954 ACSR			0				0

TRANSMISSION LINE STATISTICS

Line No.	Size of Conductor and Material (i)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	EXPENSES, EXCEPT DEPRECIATION AND TAXES	EXPENSES, EXCEPT DEPRECIATION AND TAXES	EXPENSES, EXCEPT DEPRECIATION AND TAXES	EXPENSES, EXCEPT DEPRECIATION AND TAXES
		Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
30	795 AAC			0				0
31	2156 ACSS			0				0
32	1590 AAC			0				0
33	954 ACSR			0				0
34	1272 AAC			0				0
35	1272 AAC			0				0
36	1590 AAC			0				0
37	1272 ACSS			0				0
38	2156 ACSS			0				0
39	1272 AAC			0				0
40	1926 ACSR TW			0				0
41	1272 AAC			0				0
42	1272 AAC			0				0
43	1272 AAC			0				0
44	1272 ACSS			0				0
45	2388 AAC TW			0				0
46	795 ACSR			0				0
47	2156 ACSS			0				0
48	2156 ACSS			0				0
49	795 ACSR			0				0
50	795 ACSR			0				0
51	1272 ACSR			0				0
52	795 ACSR			0				0
53	795 ACSR			0				0
54	795 ACSR			0				0
55		8,662,991	190,879,832	199,542,823	3,126,173	1,999,735	893,840	6,019,748
56		1,299,199	347,591,276	348,890,475	2,628,439	6,071,343		8,699,782
57		630,911	30,520,020	31,150,931	1,962,119	789,094		2,751,213
36		12,119,711	655,734,308	667,854,019	10,239,185	9,767,442	2,899,522	22,906,149

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

<p>(a) Concept: TransmissionLineStartPoint</p>
<p>Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.</p>
<p>(b) Concept: TransmissionLineStartPoint</p>
<p>Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.</p>
<p>(c) Concept: TransmissionLineStartPoint</p>
<p>Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.</p>
<p>(d) Concept: TransmissionLineStartPoint</p>
<p>Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.</p>
<p>(e) Concept: TransmissionLineStartPoint</p>
<p>Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.</p>
<p>(f) Concept: TransmissionLineStartPoint</p>
<p>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 isowner/operator of these Transmission Lines.</p>
<p>(g) Concept: TransmissionLineStartPoint</p>
<p>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 inconjunction 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.</p>
<p>(h) Concept: TransmissionLineStartPoint</p>
<p>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 inconjunction 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.</p>
<p>(i) Concept: TransmissionLineStartPoint</p>
<p>Represents ownership of one circuit on Bonneville Power Administration's double circuit line.</p>
<p>(j) Concept: TransmissionLineStartPoint</p>
<p>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 isowner/operator of these transmission lines.</p>
<p>(k) Concept: TransmissionLineStartPoint</p>
<p>Represents ownership of one circuit on Bonneville Power Administration's double circuit line.</p>
<p>(l) Concept: TransmissionLineStartPoint</p>
<p>Represents contract with PacifiCorp whereby PGE is entitled to 1/2 the capacity of the line.</p>
<p>(m) Concept: TransmissionLineStartPoint</p>
<p>Represents partial ownership of one circuit on Bonneville Power Administration's line.</p>

(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.

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TRANSMISSION LINES ADDED DURING YEAR

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE	SUPPORTING STRUCTURE	CIRCUITS PER STRUCTURE
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)
1	Rivergate	Seaside	0.64	Steel Poles	14	1
2	Memorial	Sherwood	6.12	Steel/Wood Poles	19	1
3	Memorial	Wilsonville	0.38	Steel/Wood Poles	14	1
44	TOTAL		7.14		47	3

TRANSMISSION LINES ADDED DURING YEAR

Line No.	CIRCUITS PER STRUCTURE	CONDUCTORS	CONDUCTORS	CONDUCTORS	Voltage KV (Operating)	LINE COST
	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)
1	1	1272 ACSR			230	
2	1	795 AAC			115	
3	1	795 AAC			115	
44	3					0

TRANSMISSION LINES ADDED DURING YEAR

Line No.	LINE COST	LINE COST	LINE COST	LINE COST	Construction (q)
	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1	2,714,718	2,644,272		5,358,990	
2	1,415,713	54,997		1,470,710	
3	943,809	42,370		986,179	
44	5,074,240	2,741,639	0	7,815,879	

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SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
1	1 Substation Under 10 MVA capacity	^(af) Transmission	Unattended	115	13		8.4
2	1 Substation Under 10 MVA capacity	^(ag) Transmission	Unattended	57	13		7.5
3	1 Substation Under 10 MVA capacity	Distribution	Unattended	115	13		8.4
4	5 Substation Under 10 MVA capacity	Distribution	Unattended	57	13		36.8
5	Abermethy, Oregon City, OR	Distribution	Unattended	115	13		44.8
6	Alder, Portland, OR	^(ah) Transmission	Unattended	115	13		56
7	Amity, near Amity, OR	Distribution	Unattended	57	13		16.875
8	Arleta, Portland, OR	^(ai) Transmission	Unattended	57	13		47.6
9	^(aj) Bakeoven, BPA, Near Bakeoven, OR	Transmission	Unattended	500			
10	Banks, Banks, OR	^(al) Transmission	Unattended	57	13		20
11	Barnes, Salem, OR	Distribution	Unattended	115	13		42.4
12	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	13		464
13	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	24		170
14	Beaverton, Beaverton, OR	^(ak) Transmission	Unattended	115	13		33.6
15	Bell, near Portland, OR	^(al) Transmission	Unattended	115	13		65.8
16	Bethany, Portland, OR	^(am) Transmission	Unattended	115	13		56
17	Bethel, Salem, OR	^(an) Transmission	Unattended	230	115	13	642
18	Bethel, Salem, OR	^(ao) Transmission	Unattended	115	13		28
19	Biglow Canyon Windfarm	Transmission	Unattended	230	34.5	13	480
20	Blue Lake, Troutdale, OR	^(ap) Transmission	Unattended	230	115	13	640

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	Capacity of Substation (In Service) (In MVa) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	
21	Blue Lake, Troutdale, OR	^(a) Transmission	Unattended	115	13		56
22	^(b) Blueridge, Lexington, Oregon	Transmission	Unattended	230	35		385
23	Boones Ferry, Lake Oswego, OR	^(a) Transmission	Unattended	115	13		50
24	Boring, near Boring, OR	^(a) Transmission	Unattended	57	13		16.8
25	^(c) Broadview Subst. near Broadview, MT	Transmission	Unattended	500	230		80
26	Brookwood, near Hillsboro, OR	^(a) Transmission	Unattended	115	13		100
27	^(d) Buckley, BPA near Buckley, WA	Transmission	Unattended	500			
28	Butler, Hillsboro OR	^(a) Transmission	Unattended	115	13		300
29	Canby, near Barlow, OR	Distribution	Unattended	57	13		39.3
30	Canemah, Oregon City, OR	^(a) Transmission	Unattended	115	57	13	264.8
31	Canyon, Portland, OR	^(a) Transmission	Unattended	115	13		200
32	^(e) Captain Jack, BPA, Near Malin, OR	Transmission	Unattended	500			
33	Carty, near Boardman, OR	Transmission	Unattended	500	230	24	1170.5
34	Carty, near Boardman, OR	Transmission	Unattended	230	7.2		55
35	Carver, Carver, OR	^(a) Transmission	Unattended	230	115	13	640
36	Carver, Carver, OR	^(a) Transmission	Unattended	115	13		56
37	Cascade, St Helens, OR	Distribution	Unattended	115	13		46.4
38	Cedar Hills, near Beaverton, OR	Distribution	Unattended	115	13		56
39	Centennial, near Gresham, OR	Distribution	Unattended	115	13		39.2
40	^(f) Chemawa BPA, near Salem, OR	Transmission	Unattended	115			

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
41	(a) Chemawa BPA, near Salem, OR	Transmission	Unattended	57			
42	Clackamas, Clackamas, OR	(a2) Transmission	Unattended	115	13		43
43	Claxtar, Salem,OR	Distribution	Unattended	57	13		28
44	(b) Clearwater East, Custer County, MT	Transmission	Unattended	345	34.5	13.8	233
45	Coffee Creek, Sherwood, OR	Distribution	Unattended	115	13		28
46	(i) Colstrip Plant, near Colstrip, MT	Transmission	Unattended	500	26		164
47	(i) Colstrip Subst. near Colstrip, MT	Transmission	Unattended	500	230		100
48	Cornelius, Cornelius, OR	(ba) Transmission	Unattended	57	13		28
49	Cornelius, Cornelius, OR	(bb) Transmission	Unattended	115	57	13	140
50	Cornell, Portland, OR	Distribution	Unattended	115	13		28
51	(k) Coyote Springs, Boardman, OR	Transmission	Unattended	500			300
52	Culver, Salem, OR	(bc) Transmission	Unattended	115	13		28
53	Curtis, Portland, OR	(bd) Transmission	Unattended	115	13		16.8
54	Dayton, near Dayton , OR	(be) Transmission	Unattended	57	13		19.5
55	Dayton, near Dayton , OR	(b) Transmission	Unattended	115	57	13	125
56	Delaware, Portland, OR	(ba) Transmission	Unattended	115	13		28
57	Denny, Beaverton, OR	(bb) Transmission	Unattended	115	13		56
58	Dilley, near Forest Grove, OR	Distribution	Unattended	57	13		12.5
59	Dunns Corner, near Sandy,OR	(b) Transmission	Unattended	57	13		14
60	Durham, Tigard , OR	Distribution	Unattended	115	13		77

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
61	E., Portland, OR	(b) Transmission	Unattended	115	13		202.4
62	E., Portland, OR	(b) Transmission	Unattended	115	11		132.4
63	E., Portland, OR	(b) Transmission	Unattended	13	11		70
64	E., Portland, OR	(b) Transmission	Unattended	11			6
65	Eagle Creek, Eagle Creek, OR	Distribution	Unattended	57	13		14
66	Eastport, Portland, OR	(b) Transmission	Unattended	115	13		16.8
67	Elma, near Salem, OR	Distribution	Unattended	57	13		56
68	Estacada, Estacada, OR	Distribution	Unattended	57	13		29.6
69	Evergreen, Hillsboro, OR	(b) Transmission	Unattended	230	115	13	640
70	Evergreen, Hillsboro, OR	(b) Transmission	Unattended	115	34.5		450
71	Fairmount, Salem, OR	(b) Transmission	Unattended	115	13		25
72	Fairview, Fairview, OR	(b) Transmission	Unattended	115	13		50.4
73	Faraday, Switchyard, OR	Transmission	Unattended	115	57	13	140
74	Faraday, Switchyard, OR	Transmission	Unattended	115	13		50
75	Faraday, Switchyard, OR	Transmission	Unattended	57	11		32
76	(d) Forest Grove BPA, Forest Grove, OR	Transmission	Unattended	115			
77	(m) Fort Rock, 12 mi NE of Silver Lake, OR	Transmission	Unattended	500			
78	Garden Home, near Portland, OR	Distribution	Unattended	115	13		28
79	Glencoe, Portland, OR	Distribution	Unattended	115	13		28
80	Glencullen, Portland, OR	(b) Transmission	Unattended	115	13		24
81	Glendoveer, near Portland, OR	(b) Transmission	Unattended	115	13		50.4
82	Glisan, Gresham, OR	(b) Transmission	Unattended	115	13		56
83	Grand Ronde, Grand Ronde, OR	(b) Transmission	Unattended	115	57	13	33

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
84	Grand Ronde, Grand Ronde, OR	(bv) Transmission	Unattended	115	13		12.5
85	Grassland, near Boardman, OR	Transmission	Unattended	500			
86	Gresham, near Gresham, OR	Transmission	Unattended	230	115	13	572
87	(u) Grizzly, BPA, near Madras, OR	Transmission	Unattended	500			
88	Harborton, near Portland, OR	(bv) Transmission	Unattended	230	115	13	320
89	Harborton, near Portland, OR	(bv) Transmission	Unattended	115	13		50
90	Harmony, near Milwaukie, OR	Distribution	Unattended	115	13		50.4
91	Harrison Sub, Portland, OR	(bv) Transmission	Unattended	115	13		56
92	Hayden Island, near Portland, OR	Distribution	Unattended	115	13		33.6
93	Helvetia, Hillsboro, OR	(ca) Transmission	Unattended	115	34.5		200
94	Hemlock, Portland, Or	Distribution	Unattended	115	13		28
95	Hillcrest, Salem , OR	(cb) Transmission	Unattended	115	13		28
96	Hillsboro, Hillsboro , OR	Distribution	Unattended	57	13		43.4
97	Hogan North, Gresham, OR	Distribution	Unattended	115	13		56
98	Hogan South, Gresham, OR	(cc) Transmission	Unattended	115	57	13	125
99	Hogan South, Gresham, OR	(cd) Transmission	Unattended	115	13		56
100	Holgate, Portland, OR	Distribution	Unattended	57	13		39.2
101	Horizon, Hillsboro, OR	Transmission	Unattended	230	115	13	960
102	Huber, near Beaverton, OR	Distribution	Unattended	115	13		56
103	Indian, near Salem, OR	(ce) Transmission	Unattended	115	13		56
104	Island, near Milwaukie, OR	(cf) Transmission	Unattended	115	13		44.8
105	Jennings Lodge, Jennings Lodge, OR	Distribution	Unattended	115	13		52.5

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
106	^(o) Keeler, BPA, Hillsboro, OR	Transmission	Unattended				
107	Kelley Point, Portland, OR	Distribution	Unattended	115	13		56
108	Kelly Butte, Portland, OR	^(ca) Transmission	Unattended	115	13		56
109	King City, near King City, OR	^(cb) Transmission	Unattended	115	13		56
110	Leland, Oregon City, OR	Distribution	Unattended	57	13		28
111	Lents, near Portland, OR	^(ci) Transmission	Unattended	115	13		22.4
112	Lents, near Portland, OR	^(cj) Transmission	Unattended	57	11		20
113	Liberal, Molalla, OR	^(ck) Transmission	Unattended	115	13		14
114	Liberty, Salem, OR	^(cl) Transmission	Unattended	115	13		50.4
115	Main, Hillsboro, OR	Distribution	Unattended	57	13		84
116	^(d) Malin, BPA, near Malin, OR	Transmission	Unattended	500			
117	Market, Salem, OR	^(cm) Transmission	Unattended	115	13		28
118	Marquam, Portland OR	^(cn) Transmission	Unattended	115	13		250
119	McClain, Salem, OR	^(co) Transmission	Unattended	57	13		22.5
120	McGill, Gresham, OR	^(cp) Transmission	Unattended	115	13		75.4
121	McLoughlin, near Oregon City, OR	^(cq) Transmission	Unattended	230	115	13	640
122	Memorial, Wilsonville, OR	^(cr) Transmission	Unattended	115	13		50
123	Meridian, near Tualatin, OR	^(cs) Transmission	Unattended	115	13		84
124	Middle Grove, near Middle Grove, OR	Distribution	Unattended	115	13		56
125	Midway, near Portland, OR	Distribution	Unattended	115	13		33.6
126	Mill Creek, near Salem, OR	^(ct) Transmission	Unattended	115	13		16.8
127	Mobile No. 1, OR	Distribution	Unattended	115	57	13	25
128	Mobile No. 2, OR	Distribution	Unattended	115	57	13	34
129	Mobile No. 3, OR	Distribution	Unattended	115	57	13	29

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
130	Mobile No. 4, OR	Distribution	Unattended	115	57	13	34
131	Mobile No. 5, OR	Distribution	Unattended	115	57	13	34
132	Mobile No. 6, OR	Distribution	Unattended	115	57	13	34
133	Mobile No. 7, OR	Distribution	Unattended	115	57	13	25
134	Mobile No. 8, OR	Distribution	Unattended	115	57	13	25
135	Molalla, Molalla, OR	^(cu) Transmission	Unattended	57	13		42.4
136	Monitor, near Monitor, OR	Transmission	Unattended	230	57	13	125
137	Mt. Angel, Mt. Angel, OR	^(cv) Transmission	Unattended	57	13		20
138	Mt. Pleasant, Oregon City, OR	Distribution	Unattended	115	13		44.8
139	Multnomah, Portland, OR	Distribution	Unattended	115	13		39.2
140	Murrayhill, Beaverton, OR	^(cw) Transmission	Unattended	115	13		56
141	Murrayhill, Beaverton, OR	^(cx) Transmission	Unattended	230	115	13	320
142	Newberg, Newberg, OR	^(cv) Transmission	Unattended	115	13		44.8
143	North Fork, near Estacada, OR	Transmission	Unattended	115	13	0.48	53
144	North Marion, near Woodburn, OR	^(cz) Transmission	Unattended	57	13		30.875
145	North Plains, North Plains, OR	^(da) Transmission	Unattended	57	13		20
146	Northern, Portland, OR	^(db) Transmission	Unattended	115	13		28
147	Oak Grove, Three Lynx, OR	^(dc) Transmission	Unattended	115	13		8
148	Oak Grove, Three Lynx, OR	^(dd) Transmission	Unattended	115	11		64
149	Oak Grove, Three Lynx, OR	^(de) Transmission	Unattended	13	11		
150	Oak Grove, Three Lynx, OR	^(df) Transmission	Unattended	13	0.48		
151	Oak Hills, near Beaverton, OR	Distribution	Unattended	115	13		44.8
152	^(g) Oregon City - BPA, Wilsonville, OR	Distribution	Unattended	57			

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
153	Orengo, near Hillsboro, OR	^(d) Transmission	Unattended	115	57	13	280
154	Orengo, near Hillsboro, OR	^(d) Transmission	Unattended	115	13		84
155	Orient, near Gresham, OR	^(d) Transmission	Unattended	57	13		28
156	Oswego, Lake Oswego, OR	^(d) Transmission	Unattended	115	13		33.6
157	Oxford, Salem, OR	^(d) Transmission	Unattended	115	13		50.4
158	^(r) Pearl, BPA, near Wilsonville, OR	Transmission	Unattended	230			
159	^(s) Pelton, near Madras, OR	Transmission	Unattended	230	13		120
160	^(t) Pelton, near Madras, OR	Transmission	Unattended	13	13		3
161	Peninsula Park, Portland, OR	Distribution	Unattended	115	13		28
162	Pleasant Valley, near Portland, OR	^(d) Transmission	Unattended	115	13		56
163	Port Westward, near Clatskanie, OR	Transmission	Unattended	230	18		900
164	Port Westward, near Clatskanie, OR	Transmission	Unattended	13	4.2		40
165	Portsmouth, Portland, OR	^(dm) Transmission	Unattended	115	13		28
166	Progress, near Tigard, OR	^(d) Transmission	Unattended	115	13		50
167	Raleigh Hills, near Portland, OR	Distribution	Unattended	115	13		28
168	Ramapo, near Portland, OR	Distribution	Unattended	115	13		28
169	Redland, near Oregon City, OR	Distribution	Unattended	115	13		22.4
170	Reedville, near Beaverton, OR	^(d) Transmission	Unattended	115	13		150
171	^(u) Rhododendron Switching, OR	Distribution	Unattended	57			
172	River Mill, near Estacada, OR	Transmission	Unattended	57	11		32
173	Rivergate North Yard, Portland, OR	^(d) Transmission	Unattended	230	115	13	386.7

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	Capacity of Substation (In Service) (In MVa) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	
174	Rivergate South Yard, Portland, OR	Distribution	Unattended	115	13		22.4
175	Rivergate South Yard, Portland, OR	Distribution	Unattended	115	11.4		22.4
176	Riverview, Portland, OR	Distribution	Unattended	115	13		28
177	Rock Creek, near Portland, OR	(d) Transmission	Unattended	115	113		28
178	Rockwood, near Gresham, OR	Distribution	Unattended	115	13		84
179	Rosemont, near Lake Oswego, OR	(d) Transmission	Unattended	115	13		28
180	Roseway, Hillsboro, OR	(d) Transmission	Unattended	115	13		56
181	(v) Round Butte, near Madras, OR	Transmission	Unattended	500	230	13	570
182	(w) Round Butte, near Madras, OR	Transmission	Unattended	230	13		394
183	Ruby, Gresham, OR	(d) Transmission	Unattended	115	13		28
184	Salem-PGE, near Salem, OR	(d) Transmission	Unattended	57	13		44.8
185	(x) Sand Springs, South of Bend, OR	Transmission	Unattended	500			
186	Sandy, Sandy, OR	Distribution	Unattended	57	13		28
187	(y) Scappoose, Scappoose, OR	Transmission	Unattended	115			
188	Scholls Ferry, Beaverton, OR	(d) Transmission	Unattended	115	13		28
189	Scoggins, near Gaston, OR	(d) Transmission	Unattended	57	13		13
190	Seaside, Portland, OR	Transmission	Unattended	230			240
191	Sellwood, Portland, OR	(d) Transmission	Unattended	115	57	13	140
192	Sellwood, Portland, OR	(d) Transmission	Unattended	115	13		28
193	Sheridan, Sheridan, OR	(d) Transmission	Unattended	57	13		16.8

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
194	Sherwood, near Six Corners, OR	Transmission	Unattended	230	115	13	640
195	Shute, Hillsboro, OR	^(ea) Transmission	Unattended	115	34.5		600
196	Silverton, Silverton, OR	^(eb) Transmission	Unattended	57	13		42
197	Six Corners, Six Corners, OR	^(ec) Transmission	Unattended	115	13		49
198	^(z) Slatt, BPA, Arlington, OR	Transmission	Unattended	500			
199	Springbrook, Newberg, OR	^(ed) Transmission	Unattended	115	13		56
200	^(ea) St. Helens, near St. Helens, OR	^(ee) Transmission	Unattended	115			
201	St. Louis, Gervais, OR	^(ef) Transmission	Unattended	57	13		23.5
202	St. Marys, East Yard, Beaverton, OR	Distribution	Unattended	115	13		56
203	St. Marys, West Yard, Beaverton, OR	^(ea) Transmission	Unattended	230	115	13	960
204	Sullivan, West Linn, OR	^(eh) Transmission	Unattended	57	4.15		33
205	Sullivan, West Linn, OR	^(ei) Transmission	Unattended	115	13		44.8
206	Summit, Government Camp, OR	Distribution	Unattended	57	13		8.4
207	Summit, Government Camp, OR	Distribution	Unattended	24	13		14
208	Sunset, near Hillsboro, OR	^(ei) Transmission	Unattended	115	13		400
209	Sunset, near Hillsboro, OR	^(ek) Transmission	Unattended	115	34.5		375
210	Swan Island, Portland, OR	Distribution	Unattended	115	13		56
211	^(eb) Sycan, 27 mi S of Silver Lake, OR	Transmission	Unattended	500			
212	Sylvan, near Portland, OR	Distribution	Unattended	115	13		22.4
213	^(ec) Tabor, Portland, OR	^(el) Transmission	Unattended	57			
214	Tabor, Portland, OR	^(em) Transmission	Unattended	115	13		22.4

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVA)	VOLTAGE (In MVA)	VOLTAGE (In MVA)	Capacity of Substation (In Service) (In MVA) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)	
215	Tektronix, Beaverton, OR	^(en) Transmission	Unattended	115	13		84
216	Temp A, OR	Distribution	Unattended	115	57	13	20
217	Temp C, OR	Distribution	Unattended	115	57	13	28
218	Temp G, OR	Distribution	Unattended	115	57	13	28
219	Temp H, OR	Distribution	Unattended	115	11		21
220	Tigard, Tigard, OR	Distribution	Unattended	115	13		44.8
221	Tonquin, Tualatin, OR	^(eo) Transmission	Unattended	115	13		56
222	Town Center, Portland, OR	^(ep) Transmission	Unattended	115	13		56
223	Trojan, near Rainier, OR	^(eq) Transmission	Unattended	230	13		56
224	^(ed) Troutdale, BPA near Troutdale OR	Transmission	Unattended	230			
225	Tualatin, Tualatin, OR	^(er) Transmission	Unattended	115	13		56
226	Tucannon Mullan Switchyard, Tucannon Dayton, Wa	Transmission	Unattended	230	34.5	13	320
227	Twilight, Canby, OR	^(es) Transmission	Unattended	57	13		28
228	University, Salem, OR	^(et) Transmission	Unattended	115	13		22.4
229	Urban, Portland, OR	^(eu) Transmission	Unattended	115	13		106.4
230	Wacker, Portland, OR	^(ev) Transmission	Unattended	115	13		56
231	Waconda, near Hopmere, OR	^(ew) Transmission	Unattended	57	13		40.6
232	Wallace, Salem, OR	^(ex) Transmission	Unattended	57	13		28
233	Welches, near Welches, OR	Distribution	Unattended	57	24		10
234	Welches, near Welches, OR	Distribution	Unattended	57	13		18
235	^(ee) West Portland, Lower Yard, Tigard, OR	^(ex) Transmission	Unattended	115			

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	Capacity of Substation (In Service) (In MVa) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	
236	West Portland, Upper Yard, Tigard, OR	^(e) Transmission	Unattended	115	13		56
237	West Union, near Hillsboro, OR	^(a) Transmission	Unattended	115	13		56
238	Willamina, near Willamina, OR	Distribution	Unattended	57	13		30.8
239	Willbridge, Portland, OR	Distribution	Unattended	115	11		28
240	Wilsonville, near Wilsonville, OR	^(b) Transmission	Unattended	115	13		84
241	Woodburn, Woodburn, OR	^(c) Transmission	Unattended	57	13		42
242	Yamhill, near Yamhill, OR	^(d) Transmission	Unattended	57	13		15.3
244	Distribution Substations			6,627	1,347.4	143	2,321.375
245	Distribution Substations Unattended			6,627	1,347.4	143	2,321.375
246	Transmission Substations			26,979	4,702.53	350.28	22,309.275
247	Transmission Substations Unattended			26,979	4,702.53	350.28	22,309.275
248	Total						24,630.65

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
1	1				
2	1				
3	1		Capacitor Banks	2	3.6
4	5				
5	2		Capacitor Banks	4	12
6	2		Capacitor Banks	4	12
7	2				
8	2		Capacitor Banks	2	7.2
9					
10	1		Capacitor Banks	2	3
11	2		Capacitor Banks	2	6
12	4				
13	1				
14	2		Capacitor Banks	4	12
15	3		Capacitor Banks	6	18
16	2		Capacitor Banks	5	15
17	3				
18	1		Capacitor Banks	2	6
19	3				
20	2				
21	2		Capacitor Banks	4	12
22	2				
23	2		Capacitor Banks	2	7.2
24	1	1	Capacitor Banks	1	12.15
25	3				
26	2		Capacitor Banks	4	12
27					
28	2	1	Capacitor Banks	2	48
29	4				
30	4	2			
31	4		Capacitor Banks	8	28.8

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
32					
33	4				
34	1				
35	2				
36	2		Capacitor Banks	4	12
37	2	1	Capacitor Banks	4	12
38	2		Capacitor Banks	4	13.2
39	2		Capacitor Banks	2	7.2
40					
41					
42	2		Capacitor Banks	4	13.2
43	1		Capacitor Banks	2	6
44	1				
45	1		Capacitor Banks	2	6
46	3				
47	2				
48	1		Capacitor Banks	2	6
49	1	1			
50	1		Capacitor Banks	2	6
51	3				
52	1				
53	1		Capacitor Banks	2	6
54	2		Capacitor Banks	4	6
55	1				
56	1				
57	2		Capacitor Banks	2	6
58	1		Capacitor Banks	3	9
59	1		Capacitor Banks	2	3
60	4		Capacitor Banks	4	12.6
61	5		Capacitor Banks	3	21.6
62	4		Capacitor Banks	1	24

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
63	1		Capacitor Banks	1	7.2
64	1		Capacitor Banks	1	8.4
65	1				
66	1		Capacitor Banks	2	6
67	2		Capacitor Banks	4	12
68	2		Capacitor Banks	2	3.6
69	2	1	Capacitor Banks	2	48
70	3		Capacitor Banks	6	27
71	1		Capacitor Banks	1	3.6
72	2		Capacitor Banks	1	3
73	1				
74	1				
75	2				
76					
77			Series Capacitor	1	363
78	1				
79	1		Capacitor Banks	2	6
80	1		Capacitor Banks	2	6
81	2				
82	2		Capacitor Banks	4	12
83	1	1			
84	1		Capacitor Banks	2	3
85					
86	2				
87					
88	1		Capacitor Banks	1	24
89	2		Capacitor Banks	4	12
90	2		Capacitor Banks	4	12
91	2		Capacitor Banks	4	12
92	2		Capacitor Banks	4	12
93	4		Capacitor Banks	8	36

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
94	1		Capacitor Banks	2	6
95	1		Capacitor Banks	2	6
96	2		Capacitor Banks	4	14.4
97	2		Capacitor Banks	4	12
98	3				
99	2		Capacitor Banks	4	12
100	2		Capacitor Banks	2	7.2
101	3				
102	2		Capacitor Banks	2	6
103	2		Capacitor Banks	3	10.8
104	2		Capacitor Banks	4	12
105	2				
106					
107	2		Capacitor Banks	4	12
108	2		Capacitor Banks	2	6
109	2		Capacitor Banks	4	12
110	1		Capacitor Banks	2	6
111	1				
112	2				
113	1		Capacitor Banks	1	12
114	2		Capacitor Banks	3	10.2
115	3		Capacitor Banks	6	20.4
116			Reactors	3	180
117	1		Capacitor Banks	2	6
118	5		Capacitor Banks	10	54
119	3				
120	3	1	Capacitor Banks	6	18
121	2				
122	1		Capacitor Banks	2	6
123	3		Capacitor Banks	6	18

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
124	2		Capacitor Banks	4	12
125	2		Capacitor Banks	1	3.6
126	1		Capacitor Banks	2	6
127	1				
128	1				
129	1				
130	1				
131	1				
132	1				
133	1				
134	1				
135	2		Capacitor Banks	4	9
136	1	2			
137	1		Capacitor Banks	3	15
138	2				
139	2		Capacitor Banks	3	9
140	2		Capacitor Banks	3	10.8
141	1				
142	2		Capacitor Banks	4	12
143	3				
144	3		Capacitor Banks	3	15
145	1		Capacitor Banks	4	16.5
146	1				
147	1				
148	2				
149					
150					
151	2		Capacitor Banks	4	14.4
152					
153	2	1			
154	3		Capacitor Banks	6	18

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
155	1		Capacitor Banks	2	6
156	2		Capacitor Banks	2	7.2
157	2		Capacitor Banks	4	12.3
158					
159	3				
160	1				
161	1		Capacitor Banks	2	6
162	2		Capacitor Banks	4	12
163	3				
164	2				
165	1				
166	2		Capacitor Banks	4	13.8
167	1		Capacitor Banks	2	6.6
168	1		Capacitor Banks	2	6
169	1				
170	3		Capacitor Banks		
171					
172	2				
173	4	1	Capacitor Banks	1	24
174	1		Capacitor Banks	2	7.2
175	1		Capacitor Banks	2	6.716
176	1		Capacitor Banks	2	6
177	1		Capacitor Banks	2	6
178	3		Capacitor Banks	5	15
179	1		Capacitor Banks	2	6
180	2		Capacitor Banks	4	12
181	4		Reactors	4	60
182	4				
183	1		Capacitor Banks	2	6
184	2		Capacitor Banks	4	12
185			Series Capacitor	1	546

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
186	1		Capacitor Banks	2	6
187					
188	1		Capacitor Banks	2	6
189	2		Capacitor Banks	1	10.8
190	1				
191	1		Capacitor Banks	1	24
192	1		Capacitor Banks	2	6
193	1		Capacitor Banks	3	15.6
194	2	1			
195	4	1	Capacitor Banks	8	36
196	2				
197	2		Capacitor Banks	4	12
198					
199	2		Capacitor Banks	5	36
200			Capacitor Banks	1	24
201	2		Capacitor Banks	2	7.2
202	2		Capacitor Banks	4	12
203	3		Capacitor Banks	3	108
204	1				
205	2		Capacitor Banks	4	12
206	1				
207	1				
208	8		Capacitor Banks	8	43.2
209	3		Capacitor Banks	5	45.6
210	2		Capacitor Banks	4	12
211			Series Capacitor	1	546
212	1		Capacitor Banks	2	4.8
213					
214	1		Capacitor Banks	2	6
215	3		Capacitor Banks	6	18
216	1	1			

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment	Conversion Apparatus and Special Equipment
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
217	1				
218	1				
219	1				
220	2		Capacitor Banks	4	12
221	2		Capacitor Banks	4	12
222	2		Capacitor Banks	2	6
223	2				
224					
225	2		Capacitor Banks	4	14.4
226	2		Capacitors/reactors	6	90
227	1	1	Capacitor Banks	4	31.2
228	1		Capacitor Banks	2	7.2
229	4		Capacitor Banks	5	39.6
230	2		Capacitor Banks	2	6
231	2		Capacitor Banks	3	18
232	1		Capacitor Banks	2	6
233	1	1	Capacitor Banks	1	12
234	2		Capacitor Banks	2	6
235			Capacitor Banks	1	24
236	2		Capacitor Banks	4	14.4
237	2		Capacitor Banks	4	12
238	2		Capacitor Banks	3	7.8
239	1				
240	3		Capacitor Banks	6	18
241	2		Capacitor Banks	4	13.2
242	2		Capacitor Banks	1	1.8
244	106	3		124	388.316
245	106	3		124	388.316
246	307	15		339	3,321.15
247	307	15		339	3,321.15
248					

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ 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
Owned by PGE and operated by NextEra Energy
(c) 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.
(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
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(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
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(h) Concept: SubstationNameAndLocation
Owned by PGE and operated by NextEra Energy
(i) 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.
(j) 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.
(k) Concept: SubstationNameAndLocation
Contribution in aid of construction made to Bonneville Power Administration in 1995 and 2006 to FERC account 353.
(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

Line compensation only.

[\(n\)](#) Concept: SubstationNameAndLocation

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

[\(o\)](#) Concept: SubstationNameAndLocation

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

[\(p\)](#) Concept: SubstationNameAndLocation

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

[\(q\)](#) Concept: SubstationNameAndLocation

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

[\(r\)](#) Concept: SubstationNameAndLocation

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

[\(s\)](#) 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.

[\(t\)](#) 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

Switching only.

[\(v\)](#) 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.

[\(w\)](#) 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.

[\(x\)](#) Concept: SubstationNameAndLocation

Line compensation only.

[\(y\)](#) Concept: SubstationNameAndLocation

Switching only. Distribution owned by Columbia River PUD.

[\(z\)](#) Concept: SubstationNameAndLocation

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

(aa) Concept: SubstationNameAndLocation

Switching only. Distribution owned by Columbia River PUD.

(ab) Concept: SubstationNameAndLocation

Line compensation only.

(ac) Concept: SubstationNameAndLocation

Switching only.

(ad) Concept: SubstationNameAndLocation

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

(ae) Concept: SubstationNameAndLocation

Switching only.

(af) Concept: SubstationCharacterDescription

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

(ag) Concept: SubstationCharacterDescription

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

(ah) Concept: SubstationCharacterDescription

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

(ai) Concept: SubstationCharacterDescription

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

(aj) Concept: SubstationCharacterDescription

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

(ak) Concept: SubstationCharacterDescription

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

(al) Concept: SubstationCharacterDescription

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

(am) Concept: SubstationCharacterDescription

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

(an) Concept: SubstationCharacterDescription

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

(ao) Concept: SubstationCharacterDescription

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

(ap) Concept: SubstationCharacterDescription

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

[\(eu\)](#) Concept: SubstationCharacterDescription

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

[\(ev\)](#) Concept: SubstationCharacterDescription

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

[\(ew\)](#) Concept: SubstationCharacterDescription

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

[\(ex\)](#) Concept: SubstationCharacterDescription

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

[\(ey\)](#) Concept: SubstationCharacterDescription

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

[\(ez\)](#) Concept: SubstationCharacterDescription

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

[\(fa\)](#) Concept: SubstationCharacterDescription

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

[\(fb\)](#) Concept: SubstationCharacterDescription

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

[\(fc\)](#) Concept: SubstationCharacterDescription

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

[\(fd\)](#) Concept: SubstationCharacterDescription

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

Name of Respondent: Portland General Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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	8,655,687
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Administrative Services	121 SW Salmon Street Corp	Various	2,839,912
42				