e-FILING REPORT COVER SHEET

COMPANY NAME: Portland General Electric

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

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

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

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

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

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

PGE's 2021 FERC Form 1; PGE's 2021 Oregon Supp to FERC Form 1; and PGE's 2021 Annual Report to Shareholders

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

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

Print

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

May 9, 2022

Via Electronic Mail

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

RE: RE 54 PGE's 2021 Annual Report and 2021 FERC Form 1

Dear Filing Center,

Enclosed for filing are PGE's 2021 Annual Report, and 2021 FERC Form 1. This includes:

- PGE's 2021 FERC Form 1 and
- PGE's 2021 Annual Report

The following additional materials have been submitted to *puc.workpapers@puc.oregon.gov*:

- Final pre-closing trial balance by FERC account (Attachment 1);
- Oregon Supplement to the FERC Annual Report (Attachment 2); and
- Distribution of Salaries and Wages and Final Pre-Closing Trial Balance by FERC Account (Attachment 2).

Not included are five printed copies of PGE's 2021 Annual Report. PGE provides this information to Shareholders in electronic format only. The link to the Annual Report is provided below.

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

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

Sincerely,

/s/ Jaki Ferchland
Jaki Ferchland
Manager, Revenue Requirement

JF/np
cc: Bryan Conway, OPUC

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

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

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

Exact Legal Name of Respondent (Company) Portland General Electric Company	Year/Period of Report End of: 2021/ Q4

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

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

   The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. When to Submit

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

EXCERPTS FROM THE LAW

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

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

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

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

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

"Sec. 304.

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

"Sec. 309.

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

GENERAL PENALTIES

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

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Portland General Electric Company	End of: 2021/ 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	06 Title of Contact Person
Christopher Liddle	Controller & Asst. Treasurer

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	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
(503) 464-7458	(1) ☐ An Original (2) ☑ A Resubmission	04/25/2022

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	03 Signature	04 Date Signed (Mo, Da, Yr)
James A. Ajello	James A. Ajello	04/25/2022
02 Title		
Senior VP of Finance, CFO & Treasurer		

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) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	not applicable
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	not applicable
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	none
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	none
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	none
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	

LIST OF SCHEDULES (Electric Utility)

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	none
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	none
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	none
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	not applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	

LIST OF SCHEDULES (Electric Utility)			
Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
56	Common Utility Plant and Expenses	356	none
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	not applicable
61	Electric Energy Account	401a	This page was inadvertently omitted from the original submission.
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	not applicable
66	Generating Plant Statistics Pages	410	
0	Energy Storage Operations (Large Plants)	414	none
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

GENERAL INFORMATION

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

-

Christopher Liddle

Controller and Assistant Treasurer

121 SW Salmon Street Portland, OR 97204

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

-

State of Incorporation: OR

Date of Incorporation: 1930-07-25

Incorporated Under Special Law:

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

Property of respondent was not so held during the year.

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

(b) Date Receiver took Possession of Respondent Property:

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

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

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

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

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

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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 has purchased the headquarters complex in Portland, Oregon and leases the complex to the Respondent	100%	
2	World Trade Center Northwest Corporation (A wholly-owned subsidiary of 121 SW Salmon Street Corporation)	Company is the holder of the World Trade Center Franchise	100%	
3	Salmon Springs Hospitality Group, Inc.	Company provides food catering services	100%	
4	121 SW Salmon Street LLC			
5	Portland Renewable Resource Company LLC			

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	[(b)]1,025,692		
2	Senior Vice President of Finance, Chief Financial Officer and Treasurer	James A. Ajello	542,445		
3	Vice President, General Counsel and Corporate Compliance Officer	Lisa A. Kaner	453,469		
4	Vice President Strategy Regulation and Energy Supply	Brett Sims	343,716		
5	Vice President, Public Affairs	W. David Robertson	351,656		
6	Vice President, Chief Customer Officer	John McFarland	399,354		
7	Vice President, Utility Operations	Bradley Y. Jenkins	400,487		
8	Vice President, Grid Architecture, Integration and Systems Operations	Larry N. Bekkedahl	420,106		
9	Vice President, Information Technology and Chief Information Officer	John Kochavatr	396,883		
10	Vice President, Operations Services	[(a)] Kristin A. Stathis	54,173		
11	Vice President, Human Resources, Diversity, Equity and Inclusion	Anne E. Mersereau	361,753		

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OfficerName
Retired onMarch 5, 2021.
(b) Concept: OfficerSalary
Amounts shown in column (c) consist of salaries only.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	[(a)] John W. Ballantine Retired Executive Vice President, First Chicago NBD Corp.	Palm Beach, Florida		
2	Rodney L. Brown, Jr. Managing Partner, Cascadia Law Group PLLC	Seattle, Washington		
3	Jack E. Davis Chair of the Board, Portland General Electric Retired Chief Executive Officer, Arizona Public Service Co.	Santa Fe, New Mexico		
4	Kirby A. Dyess Principal, Austin Capital Management LLC	Beaverton, Oregon		
5	Mark B. Ganz Retired President and Chief Executive Officer, Cambia Health Solutions, Inc.	Portland, Oregon		
6	Kathryn J. Jackson Director, Energy & Technology Consulting, KeySource, Inc.	Cincinnati, Ohio		
7	Neil J. Nelson Retired President and Chief Executive Officer, Siltronic Corp.	Keizer, Oregon		
8	M. Lee Pelton President, CEO, The Boston Foundation	Boston, Massachusetts		
9	Maria M. Pope President and Chief Executive Officer, Portland General Electric	Portland, Oregon		
10	[(b)] Charles W. Shivery Retired President and Chief Executive Officer, Northeast Utilities	Longboat Key, Florida		
11	Marie Oh Huber Sr. VP, Chief Legal Officer, General Counsel and Secretary, eBay Inc.	San Jose, California		
12	Michael H. Millegan Founder and Chief Executive Officer, Millegan Advisory Group 3 LLC	Kirkland, Washington		
13	Michael L. Lewis Retired Interim President of Pacific Gas and Electric Co.	Bethesda, Maryland		

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)
14	James P. Torgerson Retired Chief Executive Officer, AVENGRID, Inc.	Brandford, Connecticut		
15	(c) Dawn L. Farrell Retired President and CEO, TransAlta Corporation	Calgary, Alberta, Canada		

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector
Retired from Board on April 27, 2021.
(b) Concept: NameAndTitleOfDirector
Retired from Board on April 27, 2021.
(c) Concept: NameAndTitleOfDirector
Appointed to board effective January 1, 2022.

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 20, 2022, issued an order in Docket No. ES22-18-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2024. 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, 2021, PGE amended and restated its existing revolving credit facility.As of December 31, 2021, PGE had a $650 million unsecured revolving credit facility scheduled to expire in September 2026.The Company has the ability to expand the revolving credit facility to $750 million, if needed.The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% of the facility approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. In addition, the Credit Facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and to provide cash for general corporate purposes. PGE may borrow for one, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the remaining term of the credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility. The Company has elected to limit its borrowings under the revolving credit facility in order to allow coverage for the potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2021, PGE had no commercial paper outstanding.

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

Under the revolving credit facility, as of December 31, 2021, PGE hadno borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2021, the aggregate unused available credit capacity under the revolving credit facility was $650 million.

In addition, PGE has three letter of credit facilities that provide a total capacity of $220 million. 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 $79 million were outstanding, as of December 31, 2021. Letters of credit issued are not reflected on the Company's Comparative Balance Sheet.

On April 9, 2020, PGE obtained a 364-day term loan from lenders in the aggregate principal of $150 million. The term loan bore interest for the relevant interest period at LIBOR plus 1.25%. On March 31, 2021, this term loan was repaid in full with proceeds from the subsequent term loan described below. The credit agreement was classified as Notes Payable on the Company's Comparative Balance Sheet.

On March 31, 2021, PGE obtained an unsecured 364-day term loan in the aggregate principal amount of $200 million. The term loan bore interest for the relevant interest period at LIBOR plus 0.70%, with the interest rate subject to adjustment pursuant to terms of the loan. The term loan was paid off early on September 30, 2021 with proceeds from a First Mortgage Bond (FMB) issuance.

On January 6, 2021, the Company made a $140 million scheduled repayment on a 2.51% Series of FMBs with available cash. On August 11, 2021, the Company made a scheduled $20 million repayment of a 9.31% Series of FMBs with available cash.

During 2021, PGE issued a total of $400 million of FMBs, $150 million of which were issued under PGE's Green Financing Framework, which allows the Company to issue bonds and other debt instruments to finance or refinance eligible green projects.

On September 30, 2021, PGE issued $400 million in FMBs. The Bonds consist of:

- a series, due in 2028, in the amount of $100 million that will bear an interest from its issuance date at an annual rate of 1.82%;
- a series, due in 2031, in the amount of $50 million that will bear an interest from its issuance date at an annual rate of 2.10%;
- a series, due in 2034, in the amount of $100 million that will bear an interest from its issuance date at an annual rate of 2.20%; and
- a series, due in 2051, in the amount of $150 million that will bear an interest from its issuance date at an annual rate of 2.97%.

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, 2021, 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:

Securities Case

During September and October, 2020, three putative class action complaints were filed in U.S. District Court for the District of Oregon against PGE and certain of its officers, captioned*Hessel v. Portland General Electric Co*., No. 20-cv-01523 (*"Hessel"*),*Cannataro v. Portland General Electric Co*., No. 3:20-cv-01583 (*"Cannataro"*), and*Public Employees' Retirement System of Mississippi v. Portland General Electric Co*., No. 20-cv-01786 (*"PERS of Mississippi"*). Two of these actions were filed on behalf of purported purchasers of PGE stock between April 24, 2020, and August 24, 2020; a third action was filed on behalf of purported purchasers of PGE stock between February 13, 2020, and August 24, 2020.

During the fourth quarter of 2020, the plaintiff in*Hessel*voluntarily dismissed his case and the court consolidated*Cannataro*and*PERS of Mississippi*into a singlecase captioned*In re Portland General Electric Company Securities Litigation*(the "Securities Action")and appointed Public Employees' Retirement System of Mississippi lead plaintiff ("Lead Plaintiff"). On January 11, 2021,Lead Plaintiff filed an amended complaint asserting causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 for alleged misstatements and omissions regarding, among other things, PGE's alleged lack of sufficient internal controls and risks associated with PGE's trading activity in wholesale electric markets, purportedly on behalf of purchasers of PGE stock between February 13, 2020, and August 24, 2020 ("the Amended Complaint"). The Amended Complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees. On March 12, 2021, the defendants filed a motion to dismiss the Amended Complaint.

On July 11, 2021, the parties entered into a Stipulation of Settlement (the "Agreement") to fully resolve the Securities Action. The Agreement, which is subject to Court approval, provides for a settlement payment of $6.75 million in exchange for the complete dismissal with prejudice and a release of all claims against the defendants in connection with the Securities Action, without any admission of fault or wrongdoing by the defendants. On July 16, 2021, the Lead Plaintiff filed an application for Court approval of the settlement. In an order dated August 10, 2021, the Court granted preliminary approval of the settlement, stayed all proceedings in the action except with respect to settlement, and scheduled a final settlement approval hearing for March 11, 2022. The settlement payment was paid by the Company's insurance provider under its insurance policy. In light of the Agreement, the Court removed the hearing on the defendants' pending motion to dismiss from the calendar. At the hearing on March 11, 2022, the Court approved the settlement and on March 28, 2022, the Court entered a final Judgment and Order of Dismissal with Prejudice.

Putative Shareholder Derivative Lawsuits

On January 26, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned Shimberg v. Pope, No. 21- cv-02957, (the "Shimberg Action") against one current and one former PGE executive and certain members and former members of the Company's Board of Directors and naming the Company as a nominal defendant only. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company of not less than $10 million, equitable relief to remedy the alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs. On June 1, 2021, the plaintiff filed an unopposed motion to consolidate this lawsuit with the Ashabraner Action (described below), which the Court granted in an order dated July 27, 2021.

On March 17, 2021, a putative shareholder derivative lawsuit was filed in U.S. District Court for the District of Oregon, captioned JS Halberstam Irrevocable Grantor Trust v. Davis, No. 3:21-cv-00413-SI, (the "JS Halberstam Action") against one current and one former PGE executive and certain current and former members of the Company's Board of Directors. The plaintiff asserts claims for alleged breaches of fiduciary duties, waste of corporate assets, contribution and indemnification, aiding and abetting, and gross mismanagement, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks equitable relief to remedy and prevent future alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, Ashabraner v. Pope, 21-cv-13698 the "Ashabraner Action"), against one current and one former PGE executive and certain and former members of the Company's Board of Directors. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company, equitable relief, and an award of plaintiff's attorneys' fees and costs. On July 27, 2021, the Court issued an order consolidating the Ashabraner Action with the Shimberg Action.

On May 21, 2021, a putative shareholder derivative lawsuit was filed in the U.S. District Court for the District of Oregon, Portland Division captioned Berning v. Pope, No. 3:21-cv-00783-SI, (the "Berning Action"; collectively with the Shimberg, JS Halberstam, and Ashabraner Actions, the "Derivative Actions"), against one current and one former PGE executive and certain current and former members of the Company's Board of Directors and naming the Company as a nominal defendant only. The plaintiff asserts claims for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff also asserts a claim against the two executives for contribution and indemnity based on alleged violations of Sections 10(b) and 21D of the Exchange Act. The complaint demands a jury trial and seeks multiple forms of relief, including, among other things: a declaration that defendants breached and/or aided and abetted the breach of their fiduciary duties to PGE; an order directing PGE to reform and improve its corporate governance and internal procedures; restitution; and an award of attorneys' fees, expenses, and costs.

On December 17, 2021, the parties to the Derivative Actions entered into a Memorandum of Understanding to settle the Derivative Actions subject to court approval and other terms (the "MOU"). After the parties entered into the MOU, the Court in the Shimberg and Ashabraner Actions granted an order to abate the proceedings until June 21, 2022. On December 17, 2021, the parties in the JS Halberstam Action filed a motion to stay the proceedings pending submission and court review of the settlement contemplated in the MOU.

On February 11, 2022, the parties to the Derivative Actions entered into a Stipulation of Settlement memorializing the terms of the non-monetary settlement, subject to Court approval, as set forth in the MOU. Under the Stipulation of Settlement, the parties to the JS Halberstam Action agree to stay the proceedings in the Derivative Actions pending Court approval of the settlement. In addition, the Stipulation of Settlement provides that defendants will not oppose or object to a request by plaintiffs' counsel for fees and expenses up to $750,000, which is subject to Court approval. Upon final approval of the Court, PGE expects such fees and expenses to be paid by the Company's insurance provider under its insurance policy. On February 15, 2022, the plaintiffs to the JS Halberstam Action filed a motion for preliminary approval of the settlement.

On March 28, 2022, the United States District Court for the District of Oregon entered an order preliminarily approving the proposed settlement and the form and content of the notice to shareholders and setting a settlement hearing in the previously-disclosed putative shareholder derivative lawsuit captioned JS Halberstam Irrevocable Grantor Trust v. Davis, No. 3:21-cv-00413-SI. The terms of the proposed settlement are subject to final Court approval, the hearing date for which is May 9, 2022.

Governmental Investigations

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

Colstrip Related Litigation

The Company has a 20% ownership interest in the Colstrip, which is operated by one of the co-owners, Talen Montana, LLC (Talen). Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. In addition, other parties have brought claims against the co-owners, which, along with the co-owner disagreements, are described below.

Petition to compel arbitrationOn April 12, 2021, Avista Corporation, Puget Sound Energy Inc., PacifiCorp, and Portland General Electric Company (the Petitioners) petitioned in Spokane County Superior Court, Washington, Case No. 21201000-32, against NorthWestern Corporation (NorthWestern) and Talen to compel the arbitration initiated by NorthWestern to determine whether owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. On April 14, 2021, the Petitioners filed a petition to compel arbitration. On May 14, 2021, Talen removed the case to Federal Court (Eastern District of Washington Case No. 2:21-cv-00163-RMP). Petitioners filed a motion to remand on June 4, 2021, which was denied. Talen filed a motion, which, following a hearing in July 2021, was granted, to transfer the case to the U.S. District Court for the District of Montana.

Challenge to constitutionality of Montana Senate Bills 265 and 266 (SB 265 and SB 266)On May 4, 2021, the Petitioners filed a claim against NorthWestern and Talen in U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00047-SPW-KLD, based on the passage of SB 265 in Montana, which attempts to void contractual provisions within the co-owner agreement for Colstrip if they do not provide for three arbitrators or provide for venue outside of the county where the plant is located. The passage of SB 265 was supported by Defendants and purports to void the O&O Agreement between all parties, which provides for one arbitrator and venue in Spokane, Washington. The petitioners allege that SB 265 violates the contracts clause of the U.S. Constitution and the Montana Constitution, and is preempted by the Federal Arbitration Act (FAA). The Petitioners seek declaratory relief that SB 265 is unconstitutional as applied to the O&O Agreement and the FAA preempts the enforcement of SB 265.

Petitioners filed a First Amended Complaint on May 19, 2021, adding the Attorney General of Montana (Montana AG) as defendant and challenging the constitutionality of Montana Senate Bill 266 (SB 266), which purportedly gives the Montana AG authority to penalize and restrain any co-owner of Colstrip who takes steps to shut-down the plant without unanimous consent, or otherwise fails to pay the costs to maintain the plant. Defendant Northwestern filed an answer on June 2, 2021 and asked that the case Talen filed, as described in the "Complaint to implement SB 265 and SB 266" below, and this case be consolidated. On May 27, 2021, Petitioners filed a Motion for Preliminary Injunction, to enjoin the Montana AG from enforcing SB 266 against them. On June 17, 2021, defendants NorthWestern and Talen filed their Oppositions to Motion for Preliminary Injunction (PI) and the Montana AG filed a response taking no position on the PI, stating the State of Montana does not envision enforcing SB 266 any time soon. The Court held a hearing on the Petitioners' Motion for PI August 6, 2021. On October 13, 2021, the Court issued an order that granted the Petitioners' Motion for PI, enjoining the Montana AG from enforcing SB 266 against them and on December 17, 2021, the Court further clarified its PI order.

On August 17, 2021, the Petitioners filed for partial summary judgment on their claim to declare unconstitutional or unenforceable SB 265, which purports to invalidate the arbitration provision of the parties' contract. Talen opposes the motion and Northwestern does not oppose the motion, but requests the Court compel arbitration. On October 29, 2021, the Petitioners filed a motion for summary judgment on their claim to declare unconstitutional and unenforceable SB 266. In November 2021, parties file responses, opposition, and a motion to stay action on the summary judgment. On December 3, 2021, NorthWestern moved to compel arbitration and to appoint a magistrate to oversee the arbitrator selection process. On December 23, 2021, Petitioners and Talen filed their responses. The Court set a status conference for February 15, 2022.

Complaint to implement SB 265 and SB 266On May 4, 2021, Talen filed a complaint against the Petitioners and NorthWestern, in the Thirteenth Judicial District Court in the State of Montana, as an attempt to implement Montana laws when determining the language of the O&O agreement based on the recent enactment of SB 265, which purports to invalidate provisions of the co-owner operating agreement regarding arbitration, and SB 266, which purports to give the Montana AG authority to prosecute and levy a $100,000 a day fine against any co-owner who takes steps to close Colstrip without unanimous consent of all co-owners. The case was subsequently removed to the U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00058-SPW-TJC. Talen filed a motion to remand the case to the State of Montana District Court. Petitioners and NorthWestern have filed a motion to consolidate this case with the Challenge to constitutionality of Montana Senate Bills 265 and 266, described above. On October 21, 2022, the Court stayed the motion to consolidate pending the outcome of Talen's petition to remand. On December 1, 2021, the U.S. Magistrate Judge issued Findings and Recommendations to remand the case back to state Court. On December 15, 2021, the Petitioners filed Objections to the Findings and Recommendation.

Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al. On December 14, 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. On August 26, 2021, the claim was amended to add PGE as a defendant. On November 1, 2021, the defendants filed an answer to the complaint. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court.

Since these lawsuits are in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible losses.

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

Kristin Stathis, Vice President of Operations Services, retired on March 5, 2021.

Effective May 3, 2021, Larry Bekkedahl was promoted to Sr. Vice President, Advanced Energy Delivery.

The number of directors on the Board decreased from fourteen to twelve effective as of the 2021 annual shareholders' meeting held on April 28, 2021, at which time John Ballantine and Charles Shivery retired from the Board in accordance with the Company's director retirement age policy.

On October 26, 2021, the Board of Directors appointed Dawn. L. Farrell to serve as a director of the Company, effective January 1, 2022.

14. None

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	11,855,629,261	11,014,910,106
3	Construction Work in Progress (107)	200	317,489,515	430,009,860
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		12,173,118,776	11,444,919,966
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,168,097,757	4,871,352,378
6	Net Utility Plant (Enter Total of line 4 less 5)		7,005,021,019	6,573,567,588
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	0	
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	
10	Spent Nuclear Fuel (120.4)		0	
11	Nuclear Fuel Under Capital Leases (120.6)		0	
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	0	
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,005,021,019	6,573,567,588
15	Utility Plant Adjustments (116)		0	
16	Gas Stored Underground - Noncurrent (117)		0	
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		2,595,247	5,782,688
19	(Less) Accum. Prov. for Depr. and Amort. (122)		467,810	558,688
20	Investments in Associated Companies (123)		0	
21	Investment in Subsidiary Companies (123.1)	224	83,200,892	82,086,960
23	Noncurrent Portion of Allowances	228	0	
24	Other Investments (124)		4,850,418	
25	Sinking Funds (125)		0	
26	Depreciation Fund (126)		0	
27	Amortization Fund - Federal (127)		0	
28	Other Special Funds (128)		96,398,039	92,280,433

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)
29	Special Funds (Non Major Only) (129)		0	
30	Long-Term Portion of Derivative Assets (175)		34,946,317	12,278,655
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		221,523,103	191,870,048
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	
35	Cash (131)		8,267,481	1,777,290
36	Special Deposits (132-134)		37,141,298	7,985,779
37	Working Fund (135)		0	5,000
38	Temporary Cash Investments (136)		44,000,000	255,000,000
39	Notes Receivable (141)		0	
40	Customer Accounts Receivable (142)		181,230,082	161,079,488
41	Other Accounts Receivable (143)		56,123,221	27,683,325
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		26,237,603	15,642,244
43	Notes Receivable from Associated Companies (145)		0	
44	Accounts Receivable from Assoc. Companies (146)		1,286,504	809,120
45	Fuel Stock (151)	227	25,459,349	17,886,804
46	Fuel Stock Expenses Undistributed (152)	227	0	
47	Residuals (Elec) and Extracted Products (153)	227	0	
48	Plant Materials and Operating Supplies (154)	227	48,295,804	46,230,120
49	Merchandise (155)	227	0	
50	Other Materials and Supplies (156)	227	0	
51	Nuclear Materials Held for Sale (157)	202/227	0	
52	Allowances (158.1 and 158.2)	228	1,528,000	5,004,122
53	(Less) Noncurrent Portion of Allowances	228	0	
54	Stores Expense Undistributed (163)	227	2,270,648	2,688,473
55	Gas Stored Underground - Current (164.1)		0	
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		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)
57	Prepayments (165)		71,979,456	60,346,833
58	Advances for Gas (166-167)		0	
59	Interest and Dividends Receivable (171)		0	
60	Rents Receivable (172)		0	
61	Accrued Utility Revenues (173)		117,683,800	97,058,139
62	Miscellaneous Current and Accrued Assets (174)		0	
63	Derivative Instrument Assets (175)		137,169,781	45,105,863
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		34,946,317	12,278,655
65	Derivative Instrument Assets - Hedges (176)		0	
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	
67	Total Current and Accrued Assets (Lines 34 through 66)		671,251,504	700,739,456
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		13,045,696	12,381,227
70	Extraordinary Property Losses (182.1)	230a	0	
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	90,148,743	95,486,982
72	Other Regulatory Assets (182.3)	232	500,623,391	526,544,075
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,027,290	1,062,641
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	
75	Other Preliminary Survey and Investigation Charges (183.2)		0	
76	Clearing Accounts (184)		0	24,216
77	Temporary Facilities (185)		0	3
78	Miscellaneous Deferred Debits (186)	233	10,937,917	11,241,211
79	Def. Losses from Disposition of Utility Plt. (187)		0	
80	Research, Devel. and Demonstration Expend. (188)	352	0	
81	Unamortized Loss on Reaquired Debt (189)		18,929,465	20,518,419
82	Accumulated Deferred Income Taxes (190)	234	611,265,205	617,639,369
83	Unrecovered Purchased Gas Costs (191)		0	
84	Total Deferred Debits (lines 69 through 83)		1,245,977,707	1,284,898,143

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)
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		9,143,773,333	8,751,075,235

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	1,245,720,283	1,234,951,127
3	Preferred Stock Issued (204)	250	0	
4	Capital Stock Subscribed (202, 205)		0	
5	Stock Liability for Conversion (203, 206)		0	
6	Premium on Capital Stock (207)		0	
7	Other Paid-In Capital (208-211)	253	18,789,718	18,838,837
8	Installments Received on Capital Stock (212)	252	0	
9	(Less) Discount on Capital Stock (213)	254	0	
10	(Less) Capital Stock Expense (214)	254b	23,113,532	23,113,532
11	Retained Earnings (215, 215.1, 216)	118	1,471,363,440	1,388,159,313
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	5,661,231	4,547,299
13	(Less) Reaquired Capital Stock (217)	250	0	
14	Noncorporate Proprietorship (Non-major only) (218)		0	
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(9,929,713)	(11,105,713)
16	Total Proprietary Capital (lines 2 through 15)		2,708,491,427	2,612,277,331
17	LONG-TERM DEBT			
18	Bonds (221)	256	3,298,800,000	3,058,800,000
19	(Less) Reaquired Bonds (222)	256	0	
20	Advances from Associated Companies (223)	256	0	
21	Other Long-Term Debt (224)	256	0	
22	Unamortized Premium on Long-Term Debt (225)		0	
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		354,262	378,658
24	Total Long-Term Debt (lines 18 through 23)		3,298,445,738	3,058,421,342
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		294,466,454	165,575,408
27	Accumulated Provision for Property Insurance (228.1)		0	

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)**
28	Accumulated Provision for Injuries and Damages (228.2)		7,232,587	8,157,690
29	Accumulated Provision for Pensions and Benefits (228.3)		311,391,348	410,077,224
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	
31	Accumulated Provision for Rate Refunds (229)		23,697,796	8,437,194
32	Long-Term Portion of Derivative Instrument Liabilities		90,195,814	136,458,836
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	
34	Asset Retirement Obligations (230)		269,591,828	291,070,650
35	Total Other Noncurrent Liabilities (lines 26 through 34)		996,575,827	1,019,777,002
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	150,000,000
38	Accounts Payable (232)		353,434,290	294,098,090
39	Notes Payable to Associated Companies (233)		0	
40	Accounts Payable to Associated Companies (234)		13,650,173	11,791,182
41	Customer Deposits (235)		72,906,806	15,247,123
42	Taxes Accrued (236)	262	25,933,908	26,689,924
43	Interest Accrued (237)		29,267,150	29,167,585
44	Dividends Declared (238)		40,144,573	37,932,372
45	Matured Long-Term Debt (239)		0	
46	Matured Interest (240)		0	
47	Tax Collections Payable (241)		22,565,242	15,729,568
48	Miscellaneous Current and Accrued Liabilities (242)		33,121,754	11,999,595
49	Obligations Under Capital Leases-Current (243)		24,209,640	24,192,962
50	Derivative Instrument Liabilities (244)		136,966,656	150,934,109
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		90,195,814	136,458,836
52	Derivative Instrument Liabilities - Hedges (245)		0	
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	
54	Total Current and Accrued Liabilities (lines 37 through 53)		662,004,378	631,323,673

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)
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	
57	Accumulated Deferred Investment Tax Credits (255)	266	0	
58	Deferred Gains from Disposition of Utility Plant (256)		0	
59	Other Deferred Credits (253)	269	19,581,112	15,363,396
60	Other Regulatory Liabilities (254)	278	433,439,910	421,415,109
61	Unamortized Gain on Reaquired Debt (257)		10,065	18,117
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272	0	
63	Accum. Deferred Income Taxes-Other Property (282)		834,236,978	819,161,947
64	Accum. Deferred Income Taxes-Other (283)		190,987,898	173,317,318
65	Total Deferred Credits (lines 56 through 64)		1,478,255,963	1,429,275,887
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		9,143,773,333	8,751,075,235

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	2,415,154,366	2,157,212,368			2,415,154,366	2,157,212,368
3	Operating Expenses							
4	Operation Expenses (401)	320	1,335,310,689	1,174,454,586			1,335,310,689	1,174,454,586
5	Maintenance Expenses (402)	320	165,907,236	138,006,630			165,907,236	138,006,630
6	Depreciation Expense (403)	336	318,796,594	315,333,112			318,796,594	315,333,112
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	2,813,130	(3,966,273)			2,813,130	(3,966,273)
8	Amort. & Depl. of Utility Plant (404-405)	336	57,981,551	64,345,245			57,981,551	64,345,245
9	Amort. of Utility Plant Acq. Adj. (406)	336	0				0	
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,900,000	1,751,548			1,900,000	1,751,548
11	Amort. of Conversion Expenses (407.2)		0				0	
12	Regulatory Debits (407.3)		42,205,195	40,375,546			42,205,195	40,375,546
13	(Less) Regulatory Credits (407.4)		17,083,227	793,489			17,083,227	793,489
14	Taxes Other Than Income Taxes (408.1)	262	143,889,438	136,443,033			143,889,438	136,443,033
15	Income Taxes - Federal (409.1)	262	7,528,447	7,732,855			7,528,447	7,732,855
16	Income Taxes - Other (409.1)	262	15,676,517	17,587,387			15,676,517	17,587,387
17	Provision for Deferred Income Taxes (410.1)	234, 272	391,473,121	236,124,396			391,473,121	236,124,396

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)
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	391,287,302	255,226,529			391,287,302	255,226,529
19	Investment Tax Credit Adj. - Net (411.4)	266	0				0	
20	(Less) Gains from Disp. of Utility Plant (411.6)		14,621,896	4,274			14,621,896	4,274
21	Losses from Disp. of Utility Plant (411.7)		0				0	
22	(Less) Gains from Disposition of Allowances (411.8)		0				0	
23	Losses from Disposition of Allowances (411.9)		0				0	
24	Accretion Expense (411.10)		3,197,046	6,618,600			3,197,046	6,618,600
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,063,686,539	1,878,782,373			2,063,686,539	1,878,782,373
27	Net Util Oper Inc (Enter Tot line 2 less 25)		351,467,827	278,429,995			351,467,827	278,429,995
28	Other Income and Deductions							
29	Other Income							
30	Nonutilty Operating Income							
31	Revenues From Merchandising, Jobbing and Contract Work (415)							
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)							
33	Revenues From Nonutility Operations (417)		2,707,194	3,253,422			2,707,194	
34	(Less) Expenses of Nonutility Operations (417.1)		4,606,580	3,290,215			4,606,580	

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)
35	Nonoperating Rental Income (418)		512,365	7,573			512,365	
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,113,932	2,198,090			1,113,932	
37	Interest and Dividend Income (419)		356,132	519,241			356,132	
38	Allowance for Other Funds Used During Construction (419.1)		16,515,804	15,782,670			16,515,804	
39	Miscellaneous Nonoperating Income (421)		8,011,165	(18,114,548)			8,011,165	
40	Gain on Disposition of Property (421.1)		229,709				229,709	
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		24,839,721	356,233				
42	Other Income Deductions							
43	Loss on Disposition of Property (421.2)		60,005					
44	Miscellaneous Amortization (425)							
45	Donations (426.1)		2,213,410	2,244,403			2,213,410	
46	Life Insurance (426.2)		(3,063,217)	(4,267,563)			(3,063,217)	
47	Penalties (426.3)		151,133	115,667			151,133	
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,385,189	1,219,135			1,385,189	
49	Other Deductions (426.5)		4,910,313	5,794,859			4,910,313	
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,656,833	5,106,501				
51	Taxes Applic. to Other Income and Deductions							
52	Taxes Other Than Income Taxes (408.2)	262	332,094	204,195			332,094	
53	Income Taxes-Federal (409.2)	262	(4,336,194)	(2,034,288)			(4,336,194)	

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)
54	Income Taxes-Other (409.2)	262	(1,849,003)	(865,223)			(1,849,003)	
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	6,678,363	1,616,606			6,678,363	
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	1,482,208	5,773,681			1,482,208	
57	Investment Tax Credit Adj.-Net (411.5)							
58	(Less) Investment Tax Credits (420)							
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(656,948)	(6,852,391)				
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		19,839,836	2,102,123				
61	Interest Charges							
62	Interest on Long-Term Debt (427)		127,313,142	123,508,651			127,313,142	
63	Amort. of Debt Disc. and Expense (428)		1,286,222	1,353,808			1,286,222	
64	Amortization of Loss on Reaquired Debt (428.1)		1,594,762	3,302,052			1,594,762	
65	(Less) Amort. of Premium on Debt-Credit (429)		0				0	
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		8,052	8,052			8,052	
67	Interest on Debt to Assoc. Companies (430)		0				0	
68	Other Interest Expense (431)		4,223,453	5,727,993			4,223,453	
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,492,618	7,973,064			8,492,618	
70	Net Interest Charges (Total of lines 62 thru 69)		125,916,909	125,911,388				

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)
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		245,390,754	154,620,730				
72	Extraordinary Items							
73	Extraordinary Income (434)							
74	(Less) Extraordinary Deductions (435)							
75	Net Extraordinary Items (Total of line 73 less line 74)		0					
76	Income Taxes-Federal and Other (409.3)	262						
77	Extraordinary Items After Taxes (line 75 less line 76)		0					
78	Net Income (Total of line 71 and 77)		245,390,754	154,620,730				

STATEMENT OF INCOME				
Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
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22				
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24				
25	0		0	
27	0		0	
28				
29				
30				
31				
32				
33				

STATEMENT OF INCOME				
Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
34				
35				
36				
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STATEMENT OF INCOME				
Line No.	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
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Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,384,306,520	1,374,282,139
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Reclassification of stranded tax effects due to Tax Reform			
4.2				
4.3				
4.4				
4.5				
4.6				
4.7				
4.8				
4.9				
4.10				
4.11				
9	TOTAL Credits to Retained Earnings (Acct. 439)		0	0
10	Adjustments to Retained Earnings Debit			
10.1				
10.2	Adjustments to Retained Earnings Debit		(8,667,694)	
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
10.10				

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)
10.11				
15	TOTAL Debits to Retained Earnings (Acct. 439)		(8,667,694)	0
16	Balance Transferred from Income (Account 433 less Account 418.1)		244,276,822	152,422,640
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)	238	(152,405,001)	(142,413,252)
30.2				
30.3				
30.4				
30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(152,405,001)	(142,413,252)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			14,993
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,467,510,647	1,384,306,520
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				

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)
39.2				
39.3				
39.4				
39.5				
39.6				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,793	3,852,793
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,793	3,852,793
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,471,363,440	1,388,159,313
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		4,547,299	2,364,202
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,113,932	2,198,090
51	(Less) Dividends Received (Debit)			14,993
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				
53	Balance-End of Year (Total lines 49 thru 52)		5,661,231	4,547,299

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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)	245,390,754	154,620,730
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	379,591,275	375,712,084
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Discount	2,872,932	4,647,808
5.2	Amortization of Unrecovered Plant	1,900,000	1,751,548
5.3	Net Price Risk Management Activities	(106,031,370)	12,267,046
8	Deferred Income Taxes (Net)	5,381,975	(23,259,208)
9	Investment Tax Credit Adjustment (Net)	0	
10	Net (Increase) Decrease in Receivables	(59,098,176)	(18,122,409)
11	Net (Increase) Decrease in Inventory	(5,744,282)	24,113,641
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	55,566,699	24,612,708
14	Net (Increase) Decrease in Other Regulatory Assets	(46,086,999)	(9,808,881)
15	Net Increase (Decrease) in Other Regulatory Liabilities	71,818,085	(17,330,796)
16	(Less) Allowance for Other Funds Used During Construction	16,515,804	15,782,670
17	(Less) Undistributed Earnings from Subsidiary Companies	1,113,932	2,198,090
18	Other (provide details in footnote):		
18.1	Other: Margin and Customer Deposits	28,504,164	8,967,482
18.2	Other: Operating	[(a)](21,980,311)	[(c)]37,484,662
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	534,455,010	557,675,655
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(660,956,523)	(795,174,628)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(233,451)	(47,808)

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)**
30	(Less) Allowance for Other Funds Used During Construction	(16,515,804)	(15,782,670)
31	Other (provide details in footnote):		
31.1	Other Capital Activities	[(b)](16,664,422)	(8,392,187)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(661,338,592)	(787,831,953)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	0	
39	Investments in and Advances to Assoc. and Subsidiary Companies	0	
40	Contributions and Advances from Assoc. and Subsidiary Companies	0	14,993
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Sale of Property	4,389,395	
53.2	Other Investments	(8,734,211)	451,607
53.3	Purchases of Trojan Decommissioning Securities	(10,481,917)	(5,749,505)
53.4	Sales of Trojan Decommissioning Securities	12,157,140	8,773,036
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(664,008,185)	(784,341,822)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	400,000,000	548,800,000
62	Preferred Stock		

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)**
63	Common Stock	(1,202,389)	(2,578,484)
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	(150,000,000)	150,000,000
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	248,797,611	696,221,516
72	Payments for Retirement of:		
73	Long-term Debt (b)	(160,000,000)	(97,800,000)
74	Preferred Stock		
75	Common Stock	(12,018,111)	
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	0	[(d)](1,956,000)
76.2	Debt Issue Costs	(1,775,839)	(3,407,024)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(149,965,295)	(139,766,858)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(74,961,634)	453,291,634
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)	(204,514,809)	226,625,467
88	Cash and Cash Equivalents at Beginning of Period	256,782,290	30,156,823
90	Cash and Cash Equivalents at End of Period	52,267,481	256,782,290

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities
Amounts relate primarily to prepayments
(b) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities
Amounts relate primarily to cost of removal activity
(c) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities
Amounts relate primarily to decrease in prepayments and settlements of asset retirement obligations.
(d) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities
Amount represents extinguishment costs of long term debt.

NOTES TO FINANCIAL STATEMENTS

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

Supplemental Disclosures

Supplemental Information to Statement of Cash Flows

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

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 1,777,290	$ 8,267,481
Working Funds (135)	5,000	
Temporary Cash Investments (136)	255,000,000	44,000,000
	$ 256,782,290	$ 52,267,481
	2020	**2021**
Cash paid during the year:		
Interest	$ 120,814,283	$ 128,560,129
Allowance for borrowed funds used during construction	(7,973,064)	(8,492,618)
	$ 112,841,219	$ 120,067,511
Income taxes	$ 16,770,000	$ 15,664,968
Non-cash investing and financing activities:		
Accrued capital additions	$ 72,417,164	$ 87,062,845
Accrued dividends payable	$ 37,932,372	$ 40,144,573
Preliminary engineering transferred to Construction work in progress	$ 28,433	$ 1,441,391

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. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGE's corporate headquarters. The Company's corporate headquarters is located in Portland, Oregon and its approximately four thousand square mile, state-approved service area is located entirely within the state of Oregon. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2021, PGE served approximately 917 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2021, PGE had 2,839 employees in its workforce, with 678 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. The agreements cover 614 and 64 employees and expire March 2022 and August 2022, respectively. 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, 2021 up to February 17, 2022, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 12, 2022. 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 $44 million as of December 31, 2021 and $255 million as of December 31, 2020 reflected in the Comparative Balance Sheet.

Customer Accounts Receivable

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

Provisions for Uncollectible Accounts related to retail sales are charged to Administrative and General Expenses and are recorded in the same period as the related Operating Revenues, with an offsetting credit to the Accumulated Provision for Uncollectible Accounts. Such estimates for credit losses are based on management's assessment of the current and forecasted probability of collection, aging of Customer Accounts Receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for Customer Accounts Receivable and unbilled revenues. For more information on PGE's Accumulated Provision for Uncollectible Accounts and unbilled revenues see "*Customer Accounts Receivable, Net"* in Note 3, Comparative Balance Sheet Components. A portion of PGE's Provision for Uncollectible Accounts and unbilled revenues is deferred as a regulatory asset, for more information see *"COVID-19 Impacts"* in Note 6, Regulatory Assets and Liabilities.

Provisions for Uncollectible Accounts related to wholesale sales are charged to Purchased Power and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of Customer Accounts Receivable related to wholesale sales in 2021 or 2020.

Price Risk Management

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

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

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

Physically settled electricity and natural gas sale and purchase transactions are recorded in Operating Revenues and Purchased Power, respectively, upon settlement, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased P 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 $37 million as of December 31, 2021 and $8 million as of December 31, 2020. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $18 million and $12 million as of December 31, 2021 and 2020, respectively.

Inventories

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

Utility Plant

Capitalization Policy

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

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

PGE records AFUDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. On June 30, 2020 the FERC issued a waiver that provides that, for the 12-month period starting March 2020, jurisdictional utilities may apply an alternative AFUDC calculation formula that excludes the actual outstanding short-term debt balance and replaces it with the simple average of the actual 2019 short-term debt balance. The purpose of the waiver is to allow relief from the detrimental impacts of issuing short-term debt on the allowance for equity funds used during construction in response to COVID-19. PGE adopted the waiver in the second quarter of 2020. The FERC has subsequently extended the waiver through March 31, 2022.

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 2021 and 6.9% in 2020. AFUDC from borrowed funds, reflected as a reduction to Interest Charges, was $8 million in 2021 and in 2020. AFUDC from equity funds, included in Other Income, was $17 million in 2021 and $16 million in 2020.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation Expense as a percent of the related average depreciable plant in service was 3.4% in 2021 and 3.5% in 2020. A component of Depreciation Expense includes estimated asset retirement removal costs allowed in customer prices.

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

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2030 to 2061. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	97
Wind	30
Transmission	58
Distribution	46
General	15

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

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $446 million and $388 million as of December 31, 2021 and 2020, respectively, with amortization expense of $58 million in 2021 and $64 million in 2020. Future estimated amortization expense as of December 31, 2021 is as follows: $59 million in 2022; $51 million in 2023; $46 million in 2024; $33 million in 2025; and $25 million in 2026.

Marketable Securities

Nuclear decommissioning trust

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

Non-qualified benefit plan trust

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

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

Regulatory Accounting

Regulatory Assets and Liabilities

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

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

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

Power Cost Adjustment Mechanism

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

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

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.5% for 2021 and 2020.

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, 2021, PGE's actual NVPC was $62 million above baseline NVPC, which is outside the established deadband range. Pursuant to the PCAM and related earnings test, as of December 31, 2021, PGE has deferred $29 million which represents 90% of the excess variance expected to be collected from customers. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings. For the year ended December 31, 2020, excluding certain trading losses totaling $127 million, for which PGE did not pursue recovery from customers, actual NVPC was below baseline NVPC by $13 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2020. A final determination regarding the 2020 PCAM results was made by the OPUC through a public filing and review in 2021, which confirmed no refund to customers pursuant to the PCAM for 2020.

The PCAM has resulted in no collection from, or refund to, customers since 2011.

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 Expense for Asset Retirement Costs 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 Accretion Expense for Asset (Acct 411) in the Company's Statement of Income.

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

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's Comparative Balance Sheet. As of December 31, 2021, PGE had a net regulatory liability related to Utility plant AROs in the amount of $43 million and a net regulatory asset related to Trojan decommissioning ARO activities of $90 million. As of December 31, 2020, PGE had a net regulatory liability related to Utility plant AROs in the amount of $37 million and a net regulatory asset related to Trojan decommissioning ARO activities of $88 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 7, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the 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 an asset has been impaired, or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons why the estimate cannot be made.

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

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

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

Accumulated Other Comprehensive Loss

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

Revenue Recognition

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

Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's Statement of Income. Amounts collected from customers are included in Operating Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $48 million in 2021 and $46 million in 2020.

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 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 Revenue to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Stock-Based Compensation

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

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

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

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

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,	
	2021	2020
Balance as of beginning of year	$ 16	$ 4
Increase in provision *	35	15
Amounts written off, less recoveries	(25)	(3)
Balance as of end of year	$ 26	$ 16

* PGE has deferred as a regulatory asset $29 million and $8 million in bad debt expense pursuant to the OPUC's COVID-19 deferral order as of December 31, 2021 and December 31, 2020, respectively.

Net Utility Plant

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

	As of December 31,	
	2021	2020
Utility Plant:		
Generation	$ 4,645	$ 4,466
Transmission	1,009	967
Distribution	4,470	4,137
General	918	683
Intangible	805	753
Total in service	11,847	11,006
Less: Accumulated Provision for Depreciation, Amortization, and Depletion	(5,168)	(4,871)
Total in service, net	6,679	6,135
Held for future use	9	9
Construction work in progress	317	430
Net Utility Plant	$ 7,005	$ 6,574

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, 2021 and 2020, 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, 2021				
	Level 1	Level 2	Level 3	Other[(2)]	Total
Assets:					
Temporary cash Investments	$ 44	$	$	$	$ 44
Nuclear decommissioning trust: [(1)]					
Debt securities:					
Domestic government	9	10			19
Corporate credit		14			14
Money market funds measured at NAV [(2)]				14	14
Non-qualified benefit plan trust: [(3)]					
Money market funds	1				1
Equity securitiesdomestic	4				4
Debt securitiesdomestic government	4				4

	Level 1	Level 2	Level 3	Other	Total
Price risk management activities: (1) (4)					
Electricity		16	1		17
Natural gas		115	5		120
	$ 62	$ 155	$ 6	$ 14	$ 237
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$	$ 33	$ 90	$	$ 123
Natural gas		13	1		14
	$	$ 46	$ 91	$	$ 137

(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 $36 million which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 5, Risk Management.

	December 31, 2020				
	Level 1	**Level 2**	**Level 3**	**Other(2)**	**Total**
Assets:					
Temporary cash investments	$ 255	$	$	$	$ 255
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	9	11			20
Corporate credit		13			13
Money market funds measured at NAV (2)				12	12
Non-qualified benefit plan trust: (3)					
Money market funds	1				1
Equity securitiesdomestic	7				7
Debt securitiesdomestic government	1				1
Price risk management activities: (1) (4)					
Electricity		4	4		8
Natural gas		36	1		37
	$ 273	$ 64	$ 5	$ 12	$ 354
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$	$ 5	$ 141	$	$ 146
Natural gas		4	1		5
	$	$ 9	$ 142	$	$ 151

(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 $33 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 and NQBP trusts are recorded at fair value as Other Special Funds in PGE's Comparative Balance Sheet and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

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

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

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

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

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

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

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

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

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

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2021:							
Electricity physical forwards	$	$ 90	Discounted cash flow	Electricity forward price (per MWh)	$ 16.66	$ 129.75	$ 43.73
Natural gas financial swaps	5	1	Discounted cash flow	Natural gas forward price (per Dth)	2.02	8.02	2.81
Electricity financial futures	1		Discounted cash flow	Electricity forward price (per MWh)	26.76	68.43	52.46
	$ 6	$ 91					
As of December 31, 2020:							
Electricity physical forwards	$	$ 141	Discounted cash flow	Electricity forward price (per MWh)	$ 11.17	$ 51.18	$ 29.74
Natural gas financial swaps	1	1	Discounted cash flow	Natural gas forward price (per Dth)	1.52	4.33	2.29
Electricity financial futures	4		Discounted cash flow	Electricity forward price (per MWh)	8.78	58.42	43.71
	$ 5	$ 142					

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, 2021	2020
Net liabilities from price risk management activities as of beginning of year	$ 137	$ 97
Net realized and unrealized losses/(gains) *	(50)	38
Net transfers from Level 3 to Level 2	(2)	2
Net liabilities from price risk management activities as of end of year	$ 85	$ 137
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ (55)	$ 47

* Includes $5 million in net realized gains in 2021 and $9 million in 2020.

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. During the years ended December 31, 2021 and 2020, there were no transfers into Level 3 from Level 2. 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 from Level 3 at the end of the reporting period for all of its derivative instruments.

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, 2021, the carrying amount of PGE's long-term debt was $3,299 million and its estimated aggregate fair value was $3,831 million. As of December 31, 2020, the carrying amount of PGE's long-term debt was $3,059 with an estimated aggregate fair value of $3,808 million.

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

NOTE 5: RISK MANAGEMENT

Price Risk Management

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

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the Comparative Balance Sheet, may include forward, future, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the Statement of Income. PGE also enters into non-exchange-traded weather contract options, which are accounted for using the intrinsic value method. 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,	
	2021	2020
Current assets:		
Commodity contracts:		
Electricity	$ 16	$ 4
Natural gas	86	29
Total current derivative assets	102	33
Noncurrent assets:		
Commodity contracts:		
Electricity	1	4
Natural gas	34	8
Total noncurrent derivative assets	35	12
Total derivative assets	$ 137	$ 45
Current liabilities:		
Commodity contracts:		
Electricity	$ 36	$ 13
Natural gas	11	2
Total current derivative liabilities	47	15
Noncurrent liabilities:		
Commodity contracts:		
Electricity	87	133
Natural gas	3	3
Total noncurrent derivative liabilities	90	136
Total derivative liabilities	$ 137	$ 151

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

	As of December 31,			
	2021		2020	
Commodity contracts:				
Electricity	4	MWh	6	MWh
Natural gas	181	Dth	137	Dth
Foreign currency contracts	$ 19	Canadian	$ 19	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, 2021, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $3 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2021, $1 million was for electricity and $2 million was for natural gas. As of December 31, 2020, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $2 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2020, $1 million was for electricity and $1 million was for natural gas.

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,	
	2021	2020
Commodity contracts:		
Electricity	$ (38)	$ 160
Natural Gas	(177)	(34)
Foreign currency contracts		(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 $119 million and net losses of $12 million for the years ended December 31, 2021 and 2020, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2021 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2022	2023	2024	2025	2026	Thereafter	Total
Commodity contracts:							
Electricity	$ 20	$ 2	$ 3	$ 4	$ 5	$ 72	$ 106
Natural gas	(76)	(26)	(4)				(106)
Net unrealized (gain)/loss	$ (56)	$ (24)	$ (1)	$ 4	$ 5	$ 72	$

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, 2021 was $128 million, for which the Company has posted $38 million in collateral, consisting of $18 million of letters of credit and $20 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2021, the cash requirement to either post as collateral or settle the instruments immediately would have been $101 million. As of December 31, 2021, PGE had $14 million posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Special Deposits on the Company's Comparative Balance Sheet.

As of December 31, 2021, PGE received from counterparties $68 million in collateral, consisting of $10 million of letters of credit and $58 million of cash. Increases in collateral received from counterparties is due to the increase in PGE's derivative asset position. The obligation to return cash collateral held for derivative instruments is included in Accrued expenses and other current liabilities on the Company's Comparative Balance Sheet.

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

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

NOTE 6: REGULATORY ASSETS AND LIABILITIES

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

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

	Remaining Amortization Period	As of December 31, 2021	2020
Regulatory assets:			
Price risk management	(1)	$ 55	$ 124
Pension plan	(2)	131	240
Deferred income taxes	(6)	$ 58	56
February 2021 ice storm and damage	(3)	68	
Power cost adjustment mechanism	(4)	29	
2020 Labor Day wildfire	(3)	46	15
COVID-19	(3)	36	10
Other	Various	78	82
Total regulatory assets		$ 501	$ 527
Regulatory liabilities:			
Deferred income taxes	(6)	267	295
Asset retirement obligations	(5)	43	37
Price risk management	(1)	55	18
Other	Various	68	71
Total regulatory liabilities		$ 433	$ 421

(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 not yet determined.
(4) Amortization period not yet determined. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.
(5) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(6) Refund expected primarily through amortization using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.

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

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic pension and postretirement benefit costs. For further information, see Note 10, Employee Benefits.
February 2021 ice storm and damage represent the costs not previously included for recovery in customer prices related to major storm damage incurred during the twelve months ended December 31, 2021. Such costs were 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 on February 13, 2021. On February 15, 2021, the Company filed an application for authorization to defer emergency restoration costs for the February storms (Docket UM 2156). PGE does not expect an OPUC decision on the February storm deferral until 2022. While the Company believes the full amount of the deferral is probable of recovery as PGE's prudently incurred costs were in response to the unique and unprecedented nature of the storms, the OPUC has significant discretion in making the final determination of recovery and their conclusions of overall prudence, including an earnings review, and could result in a portion, or all, of PGE's deferral being disallowed for recovery.

*Power Cost Adjustment Mechanism*As of December 31, 2021, actual NVPC was $62 million above baseline NVPC, and therefore PGE has deferred $29 million which represents 90% of the excess variance expected to be collected from customers. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings. For additional information on the PCAM, see "*Power Cost Adjustment Mechanism*" in Note 2, Summary of Significant Accounting Policies.

*Wildfire*In 2020, Oregon experienced one of the most destructive wildfire seasons on record, with over one million acres of land burned that ultimately led Oregon's Governor to declare a state of emergency on August 20, 2020. As a result, PGE has incurred costs to replace and rebuild PGE facilities damaged by the fires, as well as addressing fire-damaged vegetation and other resulting debris and hazards both in and outside of PGE's property and right-of-way. Ongoing costs include replacing equipment, enhanced tree and brush clearing, and making emergency plans in close partnership with local, state, and federal land and emergency management agencies to further expand the use of a public safety power shutoff, if the need should arise. On October 20, 2020, the OPUC formally approved PGE's request for deferral of such costs (Docket UM 2115). As of December 31, 2021 and December 31, 2020, PGE's cumulative deferred costs related to the wildfire response was $45 million and $15 million, respectively. PGE continues to assess the damage to its infrastructure and expects regulatory recovery of prudently incurred restoration costs. PGE believes the full amount of the 2020 and 2021 deferrals are probable of recovery as the Company's prudently incurred costs were in response to the unique and unprecedented nature of the wildfire events leading to the deferral. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

*COVID-19 Impacts*The COVID-19 pandemic led Oregon's Governor to declare a state of emergency on March 8, 2020 and is still in effect. Due to the adverse impacts of COVID-19 on economic activity, PGE has experienced an increase in bad debt expense, lost revenue, and other incremental costs. On March 20, 2020, PGE filed an application with the OPUC for deferral of certain incremental costs, such as bad debt expense, related to COVID-19. PGE, other utilities under the OPUC's jurisdiction, intervenors, and OPUC staff held discussions regarding the scope of costs incurred by utilities which may qualify for deferral under Docket UM2114, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers. The result of such discussions was an Energy Term Sheet (Term Sheet), which dictates costs in scope for deferral but is silent to the timing of recovery of such costs. On September 24, 2020, the Commission adopted a proposed OPUC Staff motion for Staff to execute stipulations incorporating the terms of the Term Sheet. PGE's deferral application was approved by the Commission on October 20, 2020 with final stipulations for the Term Sheet approved on November 3, 2020. As of December 31, 2021 and December 31, 2020, PGE's deferred balance was $36 million and $10 million, respectively, comprised primarily of bad debt expense in excess of what is currently considered and collected in customer prices. Amortization of any deferred costs will remain subject to OPUC review prior to amortization in customer prices and would be subject to an earnings test. PGE believes the full amount of the 2020 and 2021 deferrals is probable of recovery as the Company's prudently incurred costs were in response to the unique nature of the COVID-19 pandemic health emergency. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral 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 amortizing the excess deferred income tax balance cannot occur more rapidly than over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes.

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

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2021	2020
Trojan decommissioning activities	$ 139	$ 139
Utility plant	95	118
Non-utility property	35	34
Total asset retirement obligations	269	291

Trojan decommissioning activities represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI will store the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2059. In 2021, the Company recorded accretion of $6 million and a reduction of $6 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 $5 million in 2021 for costs incurred in 2020 and $5 million in 2020 for costs incurred in 2019 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 2021, the Company recorded an overall decrease in utility AROs of $23 million, with the change comprised of reductions of $14 million due to revisions in estimated cash flows, accretion of $3 million, and a reduction of $12 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.

In 2020, PGE performed a decommissioning study to update its ARO liability which resulted in a $21 million increase to non-utility property AROs. As part of this study, the Company also established an ARO liability of $3 million related to utility hydro generating properties. In 2020, the ARO was charged to expense in the Statement of Income, as regulatory recovery was not yet considered probable. 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. The OPUC order includes cost recovery of $4 million related to the hydro generating properties. As such, PGE established a regulatory asset and ARO balancing account, resulting in a credit to Miscellaneous Nonoperating Income (Acct 421) on the Statement of Income of $4 million in 2021.

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

	Years Ended December 31,	
	2021	2020
Balance as of beginning of year	$ 291	$ 279
Liabilities incurred		3
Liabilities settled	(18)	(18)
Accretion expense	10	10
Revisions in estimated cash flows	(14)	17
Balance as of end of year	$ 269	$ 291

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

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

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

NOTE 8: CREDIT FACILITIES

On September 10, 2021, PGE amended and restated its existing revolving credit facility. As of December 31, 2021, PGE had a $650 million revolving credit facility scheduled to expire in September 2026. The Company has the ability to expand the revolving credit facility to $750 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, 2021, PGE was in compliance with this covenant with a 55.9% debt to total capital ratio. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. The Company believes these potential adjustments will have an immaterial impact on PGE's results of operations.

Under the revolving credit facility, as of December 31, 2021, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $650 million.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2021, PGE had no commercial paper outstanding.

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 three letter of credit facilities that provide a total capacity of $220 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 $79 million of letters of credit were outstanding as of December 31, 2021. Outstanding letters of credit are not reflected on the Company's Comparative Balance Sheet.

On April 9, 2020, PGE obtained a 364-day unsecured term loan from lenders in the aggregate principal amount of $150 million. The term loan bore interest for the relevant interest period at LIBOR plus 1.25%. The interest rate was subject to adjustment pursuant to the terms of the loan. On March 31, 2021, this term loan was repaid in full with proceeds from the subsequent term loan described below.

On March 31, 2021, PGE obtained an unsecured 364-day term loan in the aggregate principal amount of $200 million. The term loan bore interest for the relevant interest period at LIBOR plus 0.70%, with the interest rate subject to adjustment pursuant to terms of the loan. The credit agreement was set to expire on March 30, 2022, with any outstanding balance due and payable on such date. The term loan was paid off early on September 30, 2021 with proceeds from an FMB issuance.

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, 2024.

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

	Year Ended December 31,	
	2021	2020
Average daily amount of short-term debt outstanding	$ 139	$ 131
Weighted daily average interest rate *	0.9 %	1.5 %
Maximum amount outstanding during the year	$ 230	$ 225

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

NOTE 9: LONG-TERM DEBT

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

	As of December 31,	
	2021	2020
First Mortgage Bonds, rates range from 1.82% to 6.88%, with a weighted average rate of 4.11%% in 2021 and 4.14% in 2020, due at various dates through 2051	$ 3,180	$ 2,940
Pollution Control Revenue Bonds, rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	3,299	3,059

*First Mortgage Bonds*On January 6, 2021, the Company made a scheduled $140 million repayment of a 2.51% Series of First Mortgage Bonds with available cash.

On August 11, 2021, the Company made a scheduled $20 million repayment of a 9.31% Series of First Mortgage Bonds with available cash.

On September 30, 2021, PGE issued $400 million in FMBs. The Bonds consist of:

- a series, due in 2028, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 1.82%;
- a series, due in 2031, in the amount of $50 million that will bear interest from its issuance date at an annual rate of 2.10%;
- a series, due in 2034, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 2.20%; and
- a series, due in 2051, in the amount of $150 million that will bear interest from its issuance date at an annual rate of 2.97%.

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.

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

As of December 31, 2021, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2022	$
2023	
2024	80
2025	
2026	
Thereafter	3,219
	$ 3,299

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.

As expected, PGE contributed no additional funds to the pension plan in both 2021 and 2020. PGE does not expect to contribute to the pension plan in 2022.

*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):

	2021			2020		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	$ 21	$ 24	$ 45	$ 19	$ 23	$ 42
Non-qualified benefit plan liabilities	27	70	97	28	75	103

*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,			
	2021		2020	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	61 %	60 %	67 %	65 %
Debt securities	39	40	33	35
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	59 %	57 %	60 %	57 %
Debt securities	41	43	40	43
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	8 %	7 %	17 %	12 %
Debt securities	13	14	6	11
Insurance contracts	79	79	77	77
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, 2021:					
Defined Benefit Pension Plan assets:					
Equity securitiesDomestic	$ 25	$	$	$	$ 25
Investments measured at NAV:					
Money market funds				6	6
Collective trust funds				764	764
Private equity funds				5	5
	$ 25	$	$	$ 775	$ 800
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$	$	$	$ 3
Equity securities:					
Domestic		4			4
International	10				10
Debt securitiesDomestic		6			6
Investments measured at NAV:					
Money market funds				6	6
Collective trust funds				8	8
	$ 13	$ 10	$	$ 14	$ 37
As of December 31, 2020:					
Defined Benefit Pension Plan assets:					
Equity securitiesDomestic	$ 49	$	$	$	$ 49
Investments measured at NAV:					
Money market funds				6	6

Collective trust funds				692	692
Private equity funds				6	6
	$ 49	$	$	$ 704	$ 753
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$	$	$	$ 4
Equity securities:					
Domestic		3			3
International	9				9
Debt securitiesDomestic government		5			5
Investments measured at NAV:					
Money market funds				5	5
Collective trust funds				9	9
	$ 13	$ 8	$	$ 14	$ 35

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

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

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

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

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

*Collective trust funds*Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset back securities assets, are included in commingled trusts or separately managed accounts. The Company believes the redemption value of the collective trust funds are likely to be the fair value, which is represented by the net asset value as a practical expedient. 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, 2021 and 2020. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2021	2020	2021	2020	2021	2020
Benefit obligation:						
As of January 1	$ 1,010	$ 905	$ 76	$ 71	$ 28	$ 26
Service cost	19	17	2	2		
Interest cost	27	31	2	2	1	1
Participants' contributions						
Actuarial loss (gain)	(26)	104	(5)	4		3
Benefit payments	(47)	(44)	(5)	(4)	(2)	(2)
Administrative expenses	(3)	(3)				
Plan amendment	(8)		1	1		
Curtailment gain						
As of December 31	$ 972	$ 1,010	$ 71	$ 76	$ 27	$ 28
Fair value of plan assets:						
As of January 1	$ 753	$ 695	$ 35	$ 34	$ 19	$ 17
Actual return on plan assets	97	105	4	2	1	1
Company contributions			3	3	3	3
Participants' contributions						
Benefit payments	(47)	(44)	(5)	(4)	(2)	(2)
Administrative expenses	(3)	(3)				
As of December 31	$ 800	$ 753	$ 37	$ 35	$ 21	$ 19
Unfunded position as of December 31	$ (172)	$ (257)	$ (34)	$ (41)	$ (6)	$ (9)
Accumulated benefit plan obligation as of December 31	$ 885	$ 907	N/A	N/A	$ 23	$ 24
Classification in Comparative Balance Sheet:						
Noncurrent asset	$	$	$	$	$ 21	$ 19
Current liability					(2)	(2)

Noncurrent liability	(172)	(257)	(34)	(41)	(25)	(26)
Net liability	$ (172)	$ (257)	$ (34)	$ (41)	$ (6)	$ (9)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (78)	$ 43	$ (7)	$ 4	$ (1)	$ 3
Net prior service credit	(9)	1				
Amortization of net actuarial loss	(22)	(17)			(1)	(1)
Amortization of prior service credit			1	1		
	$ (109)	$ 27	$ (6)	$ 5	$ (2)	$ 2
Amounts included in AOCL:*						
Net actuarial loss (gain)	$ 139	$ 239	$ (3)	$ 5	$ 14	$ 15
Prior service cost	(8)	1	(7)	(8)		
	$ 131	$ 240	$ (10)	$ (3)	$ 14	$ 15

* 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 gain of $26 million and loss of $104 million, and the changes between actual and expected return on plan assets were gains of $52 million and $61 million for the years ended December 31, 2021 and 2020, respectively.
- For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were a gain of $5 million and loss of $5 million, and the changes between actual and expected return on plan assets were gains of $2 million and $1 million for each of the years ended December 31, 2021 and 2020, 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	
	2021	2020	2021	2020	2021	2020
Service cost	$ 19	$ 17	$ 2	$ 2	$	$
Interest cost on benefit obligation	27	31	2	2	1	1
Expected return on plan assets	(45)	(44)	(2)	(2)		
Amortization of prior service credit			(1)	(1)		
Amortization of net actuarial loss	22	17			1	1
Curtailment gain						
Net periodic benefit cost	$ 23	$ 21	$ 1	$ 1	$ 2	$ 2

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

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2021	2020	2021	2020	2021	2020
Assumptions used to determine benefit obligations:						
Discount rate	2.92 %	2.64 %	2.75% - 3.11 %	2.22% - 2.92 %	2.92 %	2.64 %
Rate of compensation increase	4.26 %	3.65 %	4.13 %	4.58 %	4.10 %	4.10 %
Assumptions used to determine net periodic benefit cost:						
Discount rate	2.64 %	3.43 %	2.22% - 2.92 %	3.19% - 3.47 %	2.64 %	3.43 %
Rate of compensation increase	3.65 %	3.65 %	4.58 %	4.58 %	4.10 %	4.10 %
Long-term rate of return on plan assets	6.88 %	7.00 %	5.04 %	5.02 %	N/A	N/A

As of December 31, 2021, there are no liabilities with sensitivity to health care cost trend rates.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or a 0.25% reduction in the discount rate, would have the effect of increasing the 2021 net periodic pension expense by approximately $2 million and $3 million, respectively.

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

	Payments Due					
	2022	2023	2024	2025	2026	2027 - 2031
Defined benefit pension plan	$ 59	$ 59	$ 58	$ 57	$ 58	$ 277
Other postretirement benefits	5	5	6	6	5	19
Non-qualified benefit plans	2	3	2	2	2	11
Total	$ 66	$ 67	$ 66	$ 65	$ 65	$ 307

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

401(k) Retirement Savings Plan

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

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

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $26 million in 2021 and 2020.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2021	2020
Current:		
Federal	$ 4	$ 6
State and local	14	17
	18	23
Deferred:		
Federal		(22)
State and local	5	(1)
	5	(23)
Income tax expense	$ 23	$

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

	Years Ended December 31,	
	2021	2020
Federal statutory tax rate	21.0 %	21.0 %
Federal tax credits (1)	(11.9)	(20.5)
State and local taxes, net of federal tax benefit (2)	8.9	10.1
Flow through depreciation and cost basis differences	(0.2)	(4.9)
Local tax flow-through adjustment	(3.2)	
Amortization of excess deferred income tax (3)	(4.8)	(4.7)
Other	(1.2)	(1.0)
Effective tax rate	8.6 %	%

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation ended or will end at various dates between 2017 and 2030.
(2) In 2019, Oregon enacted HB 3427, which imposed a new gross receipts tax on companies with annual revenues in excess of $1 million and applies to tax years beginning on or after January 1, 2020. The legislation defines that the tax applies to commercial activities sourced in Oregon, less certain deductions. The resulting amount is taxed at 0.57%.
(3) The majority of excess deferred income taxes related to remeasurement under the Tax Cuts and Jobs Act 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,	
	2021	2020
Deferred Income Tax Assets:		
Employee benefits	$ 115	$ 137
Price risk management	38	42
Regulatory liabilities	39	23
Tax credits	98	77
Depreciation and amortization	312	329
Other	8	9
Total Deferred Income Tax Assets	610	617
Deferred Income Tax Liabilities:		
Depreciation and amortization	849	834
Regulatory assets	121	130
Price risk management	38	12
Other	16	16
Total Deferred Income Tax Liabilities	1,024	992
Accumulated Deferred Income Tax Liability, net	$ 414	$ 375

As of December 31, 2021, PGE has federal credit carryforwards of $98 million, consisting of PTCs, which will expire at various dates through 2041. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2021 and 2020 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2021, and 2020, PGE had no material unrecognized tax benefits.

PGE and its subsidiaries file a federal income tax return. The Company also files income tax returns in the states of Oregon, California, and Montana, and in certain local jurisdictions. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2010 and all issues were resolved related to those years. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

Local tax flow-through adjustment

The Company is subject to a local tax that is recovered through a supplemental tariff based on current tax expense, but for which the Company has also recognized deferred income tax expenses over time. Because it is probable that the local deferred taxes will be flowed through future customer prices in accordance with the supplemental tariff, PGE determined a corresponding regulatory asset should have been recorded. In the first quarter of 2021, PGE recognized a regulatory asset to defer previously recorded deferred income tax expenses in the amount of $9 million with a corresponding credit to Income tax expense reflected in the Statement of Income for the year ended December 31, 2021.

NOTE 12: EQUITY-BASED PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock or 1,500 shares (based on fair value on the purchase date), whichever is less. Two six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2021, there were 210,266 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, 2021, there were 2,459,827 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

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

	Units	Weighted Average Grant Date Fair Value
Nonvested units as of December 31, 2019	463,390	43.52
Granted	202,883	56.45
Forfeited	(17,341)	50.27
Vested	(170,536)	45.67
Nonvested units as of December 31, 2020	478,396	48.00
Granted	318,844	43.01
Forfeited	(9,754)	48.35
Vested	(212,676)	40.33
Nonvested units as of December 31, 2021	574,810	48.07

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,439,300 shares remain available for future issuance as of December 31, 2021.

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

Time-based RSUs generally vest over a period of up to three years from the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was $3 million for the year ended December 31, 2021 and $1 million for 2020.

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 and Human Resources Committee of PGE's Board of Directors. The number of RSUs that may vest under the grants is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) average megawatts of forecast energy from clean or certain low-carbon emitting resources added to PGE's energy supply portfolioand relative total shareholder return (TSR) as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 200% of the RSUs granted.

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

	2021	2020
Risk-free interest rate	0.2 %	1.4 %
Expected term (in years)	2.9	2.9
Volatility	26.1 % - 37.9 %	13.5 % - 97.3 %

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 166.5%, 133.2%, and 130.7% of awarded performance-based RSUs for the respective 2021, 2020, and 2019 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $7 million for the year ended December 31, 2021 and $9 million for 2020.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $14 million for the year ended December 31, 2021 and $11 million for 2020. Such amounts differ from those reported in Other Paid-in Capital for stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and General Expenses in the Statement of Income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to Stockholder equity of $1 million in 2021 and $2 million in 2020.

As of December 31, 2021, unrecognized stock-based compensation expense was $14 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, 2021, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

Payments Due						
2022	2023	2024	2025	2026	Thereafter	Total

Capital and other purchase commitments	$ 146	$ 58	$ 7	$ 2	$ 1	$ 43	$ 257
Purchased power:							
Electricity purchases	486	353	367	341	242	2,284	4,073
Capacity contracts	18	22	23	27	12	88	190
Public utility districts	13	12	12	11	10	31	89
Natural gas	81	44	39	38	36	202	440
Coal and transportation	27	27	27	27			108
Total	$ 771	$ 516	$ 475	$ 446	$ 301	$ 2,648	$ 5,157

*Capital and other purchase commitments*Certain commitments have been made for 2022 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

*Electricity purchases and Capacity contracts*PGE has power purchase agreements with counterparties, which expire at varying dates through 2051, and power capacity contracts through 2040. Expenses associated with these commitments are recorded in purchased Power on the Company's Statement of Income.

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

- Grant County PUD for the Priest Rapids and Wanapum Hydroelectric Projects, and
- Douglas County PUD for the Wells Hydroelectric Project.

Under 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 the Douglas County agreement, the Company is required to make monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas County's loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

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

	Capacity Charges and Revenue Bonds as of December 31, 2021	PGE's Average Share as of December 31, 2021		Contract Expiration	Total PGE Contract Costs	
		Output	Capacity (in MW)		2021	2020
Priest Rapids and Wanapum	$ 1,976	8.6 %	163	2052	$ 26	$ 25
Wells	496	17.6	105	2028	13	23

The agreements for Priest Rapids, Wanapum, and Wells 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 and transportation*The Company has a coal agreement with take-or-pay provisions related to Colstrip that expires in December 2025.

Guarantees

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2021, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

NOTE 15: LEASES

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

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

PGE does not record leases with a term of 12-months or less in the Comparative Balance Sheet. Total short-term lease costs as of December 31, 2021 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, and power purchase agreements that rely on identified plant. Variable payments are generally related to gas storage and power purchase agreements for components dependent upon variable factors, such as energy production and property taxes, and are not included in the determination of the present value of lease payments.

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

	2021	2020
Operating lease cost	$ 8	$ 8
Finance lease cost:		
Amortization of right-of-use assets	$ 7	$ 5
Interest on lease liabilities	11	10
Total finance lease cost	$ 18	$ 15

Variable lease cost	$ 24	$ 12

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

	Comparative Balance Sheet Classification	December 31, 2021	December 31, 2020
Operating Leases:			
Operating lease right-of-use assets	Net Utility Plant	$ 25	$ 44
Current liabilities	Obligations Under Capital Leases - Current	$ 4	$ 8
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	22	36
Total operating lease liabilities*		$ 26	$ 44
Finance Leases:			
Finance lease right-of-use assets	Utility Plant	$ 291	$ 145
Current liabilities	Obligations Under Capital Leases - Current	$ 20	$ 16
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	273	129
Total finance lease liabilities*		$ 293	$ 145

*Included in lease liabilities are $161 million and $25 million related to power purchase agreements for the years ended December 31, 2021 and 2020, respectively.

Lease term and discount rates were as follows:

	December 31, 2021	December 31, 2020
Weighted Average Remaining Lease Term (in years)		
Operating leases	40	26
Finance leases	23	28
Weighted Average Discount Rate		
Operating leases	3.8 %	3.6 %
Finance leases	5 %	7.3 %

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, 2021, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2022	$ 4	$ 20
2023	4	18
2024	3	18
2025	1	25
2026	1	25
Thereafter	43	377
Total lease payments	56	483
Less imputed interest	(30)	(190)
Total	$ 26	$ 293

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

	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 8	$ 8
Operating cash flows from finance leases	11	10
Financing cash flows from finance leases	6	6
Right-of-use assets obtained in leasing arrangements:		
Operating leases	$ (12)	$
Finance leases	153	

In 2021, PGE entered into a hydroelectric power purchase agreement (PPA). The PPA modified an existing operating lease by effectively extending the term of the lease from 2024 to 2040 and increasing the capacity payments in the extension period. PGE reclassified the lease from operating to finance, and the Company recorded an additional lease liability and right-of-use (ROU) asset of approximately $141 million on PGE's Comparative Balance Sheet. The energy portion of the PPA is considered variable and will not be included in the calculation of the lease liability and right-of-use asset. Any material differences between expense recognition and timing of lease payments will be deferred as a regulatory asset or liability in order to match what is anticipated to be recovered in customer prices for ratemaking purposes.

As of December 31, 2021, PGE has an additional operating lease for an energy storage agreement that has not yet commenced with an estimated present value of future lease payments of $30 million. This lease is expected to commence in 2022 with a lease term of 20 years. Future estimated lease payments are $2 million annually from 2022 through 2026 and $32 million thereafter.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2021, 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	20.00 %	1986	$ 576	$ 399	$ 7
Pelton/Round Butte (2)	66.67 %	1958 / 1964	274	87	10
Total			$ 850	$ 486	$ 17

(1) Excludes AROs and accumulated asset retirement removal costs.
(2) For more information regarding changes to PGE's ownership share in the Pelton/Round Butte Project in 2022, see Note 18, Subsequent Events.

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

The Company operated, and continues to have a 90% ownership interest in Boardman, which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. As of December 31, 2021, PGE's ARO liability for its 90% share of the decommissioning costs was $23 million.

NOTE 17: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. 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. 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.

Loss 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 an asset has been impaired, or a liability incurred, if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, 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.

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 the subsequent reporting period.

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

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

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

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

A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. With the completion of pre-remedial design sampling, Portland Harbor is now in the remedial design phase, which consists of additional technical information and data collection to be used to design the expected remedial actions. Certain PRPs, not including PGE, have entered into consent agreements to perform remedial design and the EPA has indicated it will take the initial lead to perform remedial design on the remaining areas. The Company anticipates that remedial design costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy. The EPA announced on February 12, 2021 that the entirety of Portland Harbor is under an active engineering design phase.

PGE continues to participate in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including conclusion of remedial design, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor. Based on the above facts and remaining uncertainties in the voluntary allocation process, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that represents 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 of Oregon, 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 (CTWS), 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. The Company believes that PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

The impact of costs related to EPA and NRD liabilities on the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) mechanism. As approved by the OPUC in 2017, the PHERA allows the Company to defer and recover incurred estimated liabilities and 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 general rate case. 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.

Securities Case

During September and October, 2020, three putative class action complaints were filed in U.S. District Court for the District of Oregon against PGE and certain of its officers, captioned *Hessel v. Portland General Electric Co.*, No. 20-cv-01523 (*"Hessel"*), *Cannataro v. Portland General Electric Co.*, No. 3:20-cv-01583 (*"Cannataro"*), and *Public Employees' Retirement System of Mississippi v. Portland General Electric Co.*, No. 20-cv-01786 (*"PERS of Mississippi"*). Two of these actions were filed on behalf of purported purchasers of PGE stock between April 24, 2020, and August 24, 2020; a third action was filed on behalf of purported purchasers of PGE stock between February 13, 2020, and August 24, 2020.

During the fourth quarter of 2020, the plaintiff in *Hessel* voluntarily dismissed his case and the Court consolidated *Cannataro* and *PERS of Mississippi* into a single case captioned *In re Portland General Electric Company Securities Litigation* (the "Securities Action") and appointed Public Employees' Retirement System of Mississippi lead plaintiff ("Lead Plaintiff"). On January 11, 2021, Lead Plaintiff filed an amended complaint asserting causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 for alleged misstatements and omissions regarding, among other things, PGE's alleged lack of sufficient internal controls and risks associated with PGE's trading activity in wholesale electric markets, purportedly on behalf of purchasers of PGE stock between February 13, 2020, and August 24, 2020 ("the Amended Complaint"). The Amended Complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees. On March 12, 2021, the defendants filed a motion to dismiss the Amended Complaint.

On July 11, 2021, the parties entered into a Stipulation of Settlement (the "Agreement") to fully resolve the Securities Action. The Agreement, which is subject to Court approval, provides for a settlement payment of $6.75 million in exchange for the complete dismissal with prejudice and a release of all claims against the defendants in connection with the Securities Action, without any admission of fault or wrongdoing by the defendants. On July 16, 2021, the Lead Plaintiff filed an application for Court approval of the settlement. In an order dated August 10, 2021, the Court granted preliminary approval of the settlement, stayed all proceedings in the action except with respect to settlement, and scheduled a final settlement approval hearing for March 11, 2022. The settlement payment was paid by the Company's insurance provider under its insurance policy. In light of the Agreement, the Court removed the hearing on the defendants' pending motion to dismiss from the calendar. At the hearing on March 11, 2022, the Court approved the settlement and on March 28, 2022, the Court entered a final Judgment and Order of Dismissal with Prejudice.

Putative Shareholder Derivative Lawsuits

On January 26, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned *Shimberg v. Pope*, No. 21- cv-02957, (the "*Shimberg* Action") against one current and one former PGE executive and certain members and former members of the Company's Board of Directors and naming the Company as a nominal defendant only. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company of not less than $10 million, equitable relief to remedy the alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs. On June 1, 2021, the plaintiff filed an unopposed motion to consolidate this lawsuit with the *Ashabraner* Action (described below), which the Court granted in an order dated July 27, 2021.

On March 17, 2021, a putative shareholder derivative lawsuit was filed in U.S. District Court for the District of Oregon, captioned *JS Halberstam Irrevocable Grantor Trust v. Davis*, No. 3:21-cv-00413-SI, (the "*JS Halberstam* Action") against one current and one former PGE executive and certain current and former members of the Company's Board of Directors. The plaintiff asserts claims for alleged breaches of fiduciary duties, waste of corporate assets, contribution and indemnification, aiding and abetting, and gross mismanagement, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks equitable relief to remedy and prevent future alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698 the "*Ashabraner* Action"), against one current and one former PGE executive and certain and former members of the Company's Board of Directors. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company, equitable relief, and an award of plaintiff's attorneys' fees and costs. On July 27, 2021, the Court issued an order consolidating the *Ashabraner* Action with the *Shimberg* Action.

On May 21, 2021, a putative shareholder derivative lawsuit was filed in the U.S. District Court for the District of Oregon, Portland Division captioned *Berning v. Pope*, No. 3:21-cv-00783-SI, (the "*Berning* Action"; collectively with the *Shimberg, JS Halberstam*, and *Ashabraner* Actions, the "Derivative Actions"), against one current and one former PGE executive and certain current and former members of the Company's Board of Directors and naming the Company as a nominal defendant only. The plaintiff asserts claims for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff also asserts a claim against the two executives for contribution and indemnity based on alleged violations of Sections 10(b) and 21D of the Exchange Act. The complaint demands a jury trial and seeks multiple forms of relief, including, among other things: a declaration that defendants breached and/or aided and abetted the breach of their fiduciary duties to PGE; an order directing PGE to reform and improve its corporate governance and internal procedures; restitution; and an award of attorneys' fees, expenses, and costs.

On December 17, 2021, the parties to the Derivative Actions entered into a Memorandum of Understanding to settle the Derivative Actions subject to court approval and other terms (the "MOU"). After the parties entered into the MOU, the Court in the *Shimberg* and *Ashabraner* Actions granted an order to abate the proceedings until June 21, 2022. On December 17, 2021, the parties in the *JS Halberstam* Action filed a motion to stay the proceedings pending submission and court review of the settlement contemplated in the MOU.

On February 11, 2022, the parties to the Derivative Actions entered into a Stipulation of Settlement memorializing the terms of the non-monetary settlement, subject to Court approval, as set forth in the MOU. Under the Stipulation of Settlement, the parties to the *JS Halberstam* Action agree to stay the proceedings in the Derivative Actions pending Court approval of the settlement. In addition, the Stipulation of Settlement provides that defendants will not oppose or object to a request by plaintiffs' counsel for fees and expenses up to $750,000, which is subject to Court approval. Upon final approval of the Court, PGE expects such fees and expenses to be paid by the Company's insurance provider under its insurance policy. On February 15, 2022, the plaintiffs to the *JS Halberstam* Action filed a motion for preliminary approval of the settlement.

On March 28, 2022, the United States District Court for the District of Oregon entered an order preliminarily approving the proposed settlement and the form and content of the notice to shareholders and setting a settlement hearing in the previously-disclosed putative shareholder derivative lawsuit captioned JS Halberstam Irrevocable Grantor Trust v. Davis, No. 3:21-cv-00413-SI. The terms of the proposed settlement are subject to final Court approval, the hearing date for which is May 9, 2022.

Governmental Investigations

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

Colstrip-Related Litigation

The Company has a 20% ownership interest in the Colstrip, which is operated by one of the co-owners, Talen Montana, LLC (Talen). Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. In addition, other parties have brought claims against the co-owners, which, along with the co-owner disagreements, are described below.

*Petition to compel arbitration*On April 12, 2021, Avista Corporation, Puget Sound Energy Inc., PacifiCorp, and Portland General Electric Company (the Petitioners) petitioned in Spokane County Superior Court, Washington, Case No. 21201000-32, against NorthWestern Corporation (NorthWestern) and Talen to compel the arbitration initiated by NorthWestern to determine whether owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. On April 14, 2021, the Petitioners filed a petition to compel arbitration. On May 14, 2021, Talen removed the case to Federal Court (Eastern District of Washington Case No. 2:21-cv-00163-RMP). Petitioners filed a motion to remand on June 4, 2021, which was denied. Talen filed a motion, which, following a hearing in July 2021, was granted, to transfer the case to the U.S. District Court for the District of Montana.

*Challenge to constitutionality of Montana Senate Bills 265 and 266 (SB 265 and SB 266)*On May 4, 2021, the Petitioners filed a claim against NorthWestern and Talen in U.S.

District Court - Montana, Billings Division, Case No. 1:21-cv-00047-SPW-KLD, based on the passage of SB 265 in Montana, which attempts to void contractual provisions within the co-owner agreement for Colstrip if they do not provide for three arbitrators or provide for venue outside of the county where the plant is located. The passage of SB 265 was supported by Defendants and purports to void the O&O Agreement between all parties, which provides for one arbitrator and venue in Spokane, Washington. The petitioners allege that SB 265 violates the contracts clause of the U.S. Constitution and the Montana Constitution, and is preempted by the Federal Arbitration Act (FAA). The Petitioners seek declaratory relief that SB 265 is unconstitutional as applied to the O&O Agreement and the FAA preempts the enforcement of SB 265.

Petitioners filed a First Amended Complaint on May 19, 2021, adding the Attorney General of Montana (Montana AG) as defendant and challenging the constitutionality of Montana Senate Bill 266 (SB 266), which purportedly gives the Montana AG authority to penalize and restrain any co-owner of Colstrip who takes steps to shut-down the plant without unanimous consent, or otherwise fails to pay the costs to maintain the plant. Defendant Northwestern filed an answer on June 2, 2021 and asked that the case Talen filed, as described in the *"Complaint to implement SB 265 and SB 266"* below, and this case be consolidated. On May 27, 2021, Petitioners filed a Motion for Preliminary Injunction, to enjoin the Montana AG from enforcing SB 266 against them. On June 17, 2021, defendants NorthWestern and Talen filed their Oppositions to Motion for Preliminary Injunction (PI) and the Montana AG filed a response taking no position on the PI, stating the State of Montana does not envision enforcing SB 266 any time soon. The Court held a hearing on the Petitioners' Motion for PI August 6, 2021. On October 13, 2021, the Court issued an order that granted the Petitioners' Motion for PI, enjoining the Montana AG from enforcing SB 266 against them and on December 17, 2021, the Court further clarified its PI order.

On August 17, 2021, the Petitioners filed for partial summary judgment on their claim to declare unconstitutional or unenforceable SB 265, which purports to invalidate the arbitration provision of the parties' contract. Talen opposes the motion and Northwestern does not oppose the motion, but requests the Court compel arbitration. On October 29, 2021, the Petitioners filed a motion for summary judgment on their claim to declare unconstitutional and unenforceable SB 266. In November 2021, parties file responses, opposition, and a motion to stay action on the summary judgment. On December 3, 2021, NorthWestern moved to compel arbitration and to appoint a magistrate to oversee the arbitrator selection process. On December 23, 2021, Petitioners and Talen filed their responses. The Court set a status conference for February 15, 2022.

*Complaint to implement SB 265 and SB 266*On May 4, 2021, Talen filed a complaint against the Petitioners and NorthWestern, in the Thirteenth Judicial District Court in the State of Montana, as an attempt to implement Montana laws when determining the language of the O&O agreement based on the recent enactment of SB 265, which purports to invalidate provisions of the co-owner operating agreement regarding arbitration, and SB 266, which purports to give the Montana AG authority to prosecute and levy a $100,000 a day fine against any co-owner who takes steps to close Colstrip without unanimous consent of all co-owners. The case was subsequently removed to the U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00058-SPW-TJC. Talen filed a motion to remand the case to the State of Montana District Court. Petitioners and NorthWestern have filed a motion to consolidate this case with the *Challenge to constitutionality of Montana Senate Bills 265 and 266,* described above. On October 21, 2022, the Court stayed the motion to consolidate pending the outcome of Talen's petition to remand. On December 1, 2021, the U.S. Magistrate Judge issued Findings and Recommendations to remand the case back to state Court. On December 15, 2021, the Petitioners filed Objections to the Findings and Recommendation.

Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al. On December 14, 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. On August 26, 2021, the claim was amended to add PGE as a defendant. On November 1, 2021, the defendants filed an answer to the complaint. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court.

Since these lawsuits are in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible losses.

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 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

Under terms of an agreement (the "Agreement") executed and approved by the OPUC in 2000, PGE has a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021. On June 30, 2021, the CTWS notified PGE of their intent to exercise this purchase option. Under the terms of the purchase option in the Agreement, on January 1, 2022, PGE completed the sale of the additional undivided interest in the project at a net book value of approximately $38 million, with no gain or loss recognized on the sale. 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 option is exercised, the CTWS' ownership percentage would exceed 50%. PGE remains the operator of the project.

PGE is obligated to purchase 100% of the CTWS' share of the project's output under a PPA through 2040. The exercise of the purchase option 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 being accounted for as a financing, and PGE will continue to record the asset on the Comparative Balance Sheet within Utility Plant as if it were the legal owner and will continue to recognize Depreciation Expense over the estimated useful life. A financing obligation will be recorded in Other noncurrent liabilities. The monthly PPA payments will be split between interest charges and a reduction of the principal portion of the financing obligation. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(9,615,102)	(808)		(9,615,910)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(a)](1,489,803)			(1,489,803)		
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)				(1,489,803)			(1,489,803)	154,620,730	153,130,927
5	Balance of Account 219 at End of Preceding Quarter/Year				(11,104,905)	(808)	0	(11,105,713)		
6	Balance of Account 219 at Beginning of Current Year				(11,104,905)	(808)	0	(11,105,713)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(b)]1,176,000	0		1,176,000		
8	Current Quarter/Year to Date Changes in Fair Value							0		
9	Total (lines 7 and 8)				1,176,000	0	0	1,176,000	245,390,754	246,566,754
10	Balance of Account 219 at End of Current Quarter/Year				(9,928,905)	(808)	0	(9,929,713)		

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss
Comprised of the net amount of the actuarial valuation of $(2,054,894) of non-qualified benefit plans net of taxes of $565,091.
(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss
Comprised of the net amount of the actuarial valuation of $1,622,070 of non-qualified benefit plans net of taxes of $(446,070).

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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)	9,688,763,373	9,688,763,373					
4	Property Under Capital Leases	316,455,944	316,455,944					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,841,962,426	1,841,962,426					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	11,847,181,743	11,847,181,743					
9	Leased to Others							
10	Held for Future Use	8,447,518	8,447,518					
11	Construction Work in Progress	317,489,515	317,489,515					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	12,173,118,776	12,173,118,776					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,168,097,757	5,168,097,757					
15	Net Utility Plant (13 less 14)	7,005,021,019	7,005,021,019					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	4,722,143,167	4,722,143,167					
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	445,954,590	445,954,590					
22	Total in Service (18 thru 21)	5,168,097,757	5,168,097,757					
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)							

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)
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,168,097,757	5,168,097,757					

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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
3	(302) Franchise and Consents	202,049,028	174,278	0	0	0	202,223,306
4	(303) Miscellaneous Intangible Plant	551,370,331	51,585,453	268,927	0	0	602,686,857
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	753,419,359	51,759,731	268,927	0	0	804,910,163
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	3,328,862	0	0	0	0	3,328,862
9	(311) Structures and Improvements	117,298,194	(619,011)	13,981	0	0	116,665,202
10	(312) Boiler Plant Equipment	270,806,674	5,092,569	197,828	0	0	275,701,415
11	(313) Engines and Engine-Driven Generators						0
12	(314) Turbogenerator Units	72,868,980	4,968,406	1,783,077	0	0	76,054,309
13	(315) Accessory Electric Equipment	23,952,259	1,171,788	0	0	0	25,124,047
14	(316) Misc. Power Plant Equipment	6,602,720	330,374	28,740	0	0	6,904,354
15	(317) Asset Retirement Costs for Steam Production	34,911,263	0	0	0	0	34,911,263
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	529,768,952	10,944,126	2,023,626	0	0	538,689,452
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						0
19	(321) Structures and Improvements						0
20	(322) Reactor Plant Equipment						0
21	(323) Turbogenerator Units						0
22	(324) Accessory Electric Equipment						0
23	(325) Misc. Power Plant Equipment						0
24	(326) Asset Retirement Costs for Nuclear Production						0
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	6,053,903	0	0	0	0	6,053,903
28	(331) Structures and Improvements	90,484,463	1,709,512	0	0	0	92,193,975
29	(332) Reservoirs, Dams, and Waterways	358,465,413	1,345,067	169,994	0	0	359,640,486

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)**
30	(333) Water Wheels, Turbines, and Generators	78,814,691	1,407,324	0	0	0	80,222,015
31	(334) Accessory Electric Equipment	34,286,055	3,158,074	0	0	0	37,444,129
32	(335) Misc. Power Plant Equipment	18,403,295	280,439	0	[a]136,645,637	0	155,329,371
33	(336) Roads, Railroads, and Bridges	15,697,871	1,963,620	0	0	0	17,661,491
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	0	0	0	0	5,128
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	602,210,819	9,864,036	169,994	136,645,637	0	748,550,498
36	D. Other Production Plant						
37	(340) Land and Land Rights	24,104,434	43,512	0	[b][c](2,979,211)	0	21,168,735
38	(341) Structures and Improvements	274,167,328	1,310,198	142,463	0	0	275,335,063
39	(342) Fuel Holders, Products, and Accessories	288,507,476	109,701	1,776,856	[d][e](5,049,695)	0	281,790,626
40	(343) Prime Movers						0
41	(344) Generators	2,555,129,992	20,776,901	8,782,766	[f](440,251)	0	2,566,683,876
42	(345) Accessory Electric Equipment	120,882,447	1,866,495	331,814	0	0	122,417,128
43	(346) Misc. Power Plant Equipment	45,611,839	13,186,930	0	0	0	58,798,769
44	(347) Asset Retirement Costs for Other Production	25,342,839	0	0	0	0	25,342,839
44.1	(348) Energy Storage Equipment - Production		6,337,427	0	0	0	6,337,427
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,333,746,355	43,631,164	11,033,899	(8,469,157)	0	3,357,874,463
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,465,726,126	64,439,326	13,227,519	128,176,480	0	4,645,114,413
47	3. Transmission Plant						
48	(350) Land and Land Rights	17,291,806	710,208	0	0	0	18,002,014
48.1	(351) Energy Storage Equipment - Transmission						0
49	(352) Structures and Improvements	30,414,679	696,669	257,262	0	0	30,854,086
50	(353) Station Equipment	565,408,093	13,279,323	5,099,649	0	206,738	573,794,505
51	(354) Towers and Fixtures	53,915,834	(2,134,301)	69,543	0	0	51,711,990
52	(355) Poles and Fixtures	101,020,242	22,323,290	0	0	0	123,343,532
53	(356) Overhead Conductors and Devices	198,910,256	12,508,631	123,538	0	0	211,295,349
54	(357) Underground Conduit						0
55	(358) Underground Conductors and Devices						0
56	(359) Roads and Trails	286,332	0	0	0	0	286,332

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)**
57	(359.1) Asset Retirement Costs for Transmission Plant	34,109	0	0	0	0	34,109
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	967,281,351	47,383,820	5,549,992	0	206,738	1,009,321,917
59	4. Distribution Plant						
60	(360) Land and Land Rights	19,129,106	127,380	0	0	0	19,256,486
61	(361) Structures and Improvements	46,272,435	1,897,865	143,039	0	75,400	48,102,661
62	(362) Station Equipment	616,835,382	74,282,801	1,483,735	0	(205,985)	689,428,463
63	(363) Energy Storage Equipment – Distribution	399,115	1,151,347	0	0	0	1,550,462
64	(364) Poles, Towers, and Fixtures	459,027,811	50,182,359	2,600,538	0	0	506,609,632
65	(365) Overhead Conductors and Devices	702,843,258	60,987,669	1,220,465	0	0	762,610,462
66	(366) Underground Conduit	30,936,016	1,869,764	0	0	0	32,805,780
67	(367) Underground Conductors and Devices	926,798,924	49,324,220	0	(238,620)	0	975,884,524
68	(368) Line Transformers	487,967,549	25,543,049	1,310,456	0	0	512,200,142
69	(369) Services	520,005,227	34,178,558	0	0	0	554,183,785
70	(370) Meters	195,464,069	17,688,671	2,036,377	0	0	211,116,363
71	(371) Installations on Customer Premises	2,380,138	1,177,316	0	0	203,483	3,760,937
72	(372) Leased Property on Customer Premises						0
73	(373) Street Lighting and Signal Systems	128,211,937	23,773,793	0	0	0	151,985,730
74	(374) Asset Retirement Costs for Distribution Plant	476,732	0	0	0	0	476,732
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,136,747,699	342,184,792	8,794,610	(238,620)	72,898	4,469,972,159
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						0
78	(381) Structures and Improvements						0
79	(382) Computer Hardware						0
80	(383) Computer Software						0
81	(384) Communication Equipment						0
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						0
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						0
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	0	0	0	0	0	0

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)
85	6. General Plant						
86	(389) Land and Land Rights	9,572,354	14,050,324	0	0	0	23,622,678
87	(390) Structures and Improvements	155,696,066	175,123,816	80,725	[(a)](485,521)	0	330,253,636
88	(391) Office Furniture and Equipment	152,963,807	20,485,064	41,722,656	0	0	131,726,215
89	(392) Transportation Equipment	80,831,809	3,794,232	2,884,946	0	(753)	81,740,342
90	(393) Stores Equipment	4,280,345	155,349	0	0	0	4,435,694
91	(394) Tools, Shop and Garage Equipment	23,645,550	(58,265)	484,812	0	(203,483)	22,898,990
92	(395) Laboratory Equipment	14,003,611	0	499,201	0	0	13,504,410
93	(396) Power Operated Equipment	40,944,558	9,035,113	3,425,383	0	0	46,554,288
94	(397) Communication Equipment	200,084,697	62,297,106	603,671	0	0	261,778,132
95	(398) Miscellaneous Equipment	1,288,161	(1)	4,743	0	0	1,283,417
96	SUBTOTAL (Enter Total of lines 86 thru 95)	683,310,958	284,882,738	49,706,137	(485,521)	(204,236)	917,797,802
97	(399) Other Tangible Property						0
98	(399.1) Asset Retirement Costs for General Plant	65,289	0	0	0	0	65,289
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	683,376,247	284,882,738	49,706,137	(485,521)	(204,236)	917,863,091
100	TOTAL (Accounts 101 and 106)	11,006,550,782	790,650,407	77,547,185	127,452,339	75,400	11,847,181,743
101	(102) Electric Plant Purchased (See Instr. 8)						0
102	(Less) (102) Electric Plant Sold (See Instr. 8)						0
103	(103) Experimental Plant Unclassified						0
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,006,550,782	790,650,407	77,547,185	127,452,339	75,400	11,847,181,743

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousPowerPlantEquipmentHydraulicProductionAdjustments
Includes an impact of modification of hydro project capital lease agreement which extended the term of the lease by 16 years as well as regular activities of capitalized lease assets.
(b) Concept: LandAndLandRightsOtherProductionAdjustments
Includes activities of capitalized lease assets.
(c) Concept: LandAndLandRightsOtherProductionAdjustments
Includes activities of capitalized lease assets.
(d) Concept: FuelHoldersProductsAndAccessoriesOtherProductionAdjustments
Includes activities of capitalized lease assets.
(e) Concept: FuelHoldersProductsAndAccessoriesOtherProductionAdjustments
Includes activities of capitalized lease assets.
(f) Concept: GeneratorsOtherProductionAdjustments
Includes activities of capitalized lease assets.
(g) Concept: StructuresAndImprovementsGeneralPlantAdjustments
Includes activities of capitalized lease assets.

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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]	[g]	543,591
3	Sewell, Washington County, OR	[b]	[h]	2,817,507
4	Sewell Easement, Washington County, OR	[c]	[i]	332,379
5	Evergreen, Washington County, OR	[d]	[j]	3,600,000
6	Boardman, Morrow County, OR	[e]	[k]	832,853
7	Other Land and Land Rights	[f]	[l]	321,188
21	Other Property:			
22				
23				
24				
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44				
45				
46				
47	TOTAL			8,447,518

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2007

(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2008

(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2009

(d) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2019

(e) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2020

(f) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

Various

(g) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(h) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(i) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(j) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(k) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(l) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Various

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Repower Faraday Units 1-5	109,262,275
2	Brookwood Substation Conversion	43,360,316
3	Shute Road Substation Capacity Addition	15,463,078
4	Build Evergreen Substation	14,709,877
5	Hydro Control System Upgrade	9,184,333
6	Colstrip Coal Capital Project	[a]6,658,993
7	North Portland Conversion	5,047,110
8	Facilities Upgrades-EV Readiness	5,001,172
9	Canyon-Urban 115kV Reconductor	4,864,817
10	West Side Hydro Restoration	4,651,309
11	Harborton Reliability Project	3,772,147
12	Build Memorial Substation	3,658,504
13	Blue Lake Substation Upgrade	3,341,052
14	South Milliken Distribution Line Rebuild	3,264,915
15	River District Infrastructure - Install Vaults and Conduits	2,948,213
16	Orenco Substation Rebuild	2,937,293
17	Arleta-Holgate Conversion	2,861,512
18	Stephens Substation Conversion	2,753,027
19	Centennial Substation Upgrades	2,609,511
20	Replace Turbine Shut-off Valves	[b][c][d][e]2,582,967
21	Oracle Utilities Upgrade	2,520,575
22	Milliken Tower Reinforcement	2,464,570
23	Pelton Round Butte Mitigation Enhancement Fund	[f]2,365,582
24	Carty/Boardman Separation Project	2,311,084
25	AMI Improvement Project	2,223,669
26	Distribution Line Construction	2,101,777
27	Beaver GT Upgrades	2,057,764
28	Substation Communication Upgrade	1,721,852
29	Bill Redesign	1,721,499
30	Transmission Substations Protection Upgrades	1,675,095
31	Mobile Channel Development	1,661,794
32	Beaver Modernization	1,572,892
33	Bethel to Round Butte Fiber	1,555,174
34	Upgrade Governors and Exciters	[g]1,536,410

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)		
Line No.	**Description of Project** **(a)**	**Construction work in progress - Electric (Account 107)** **(b)**
35	Hydro Habitat Restoration	[h]1,485,685
36	Small Generator/Qualified Facility (QF) Interconnection	1,427,340
37	Build Tonquin Substation	1,328,453
38	Advanced Distribution Management System Upgrade	1,302,813
39	DPU Relay Replacement	1,269,850
40	Replace or Rewind Failed Transformers	1,250,675
41	Substation Upgrade	1,168,739
42	Energy Storage	1,139,814
43	IQGeo Enterprise License	1,132,525
44	Upgrade Excitation System	1,116,774
45	Hydro Structural/Reliability Upgrades	1,006,190
46	Minor Projects, <$1 million, represents 9% of the Total CWIP Balance	27,438,499
43	Total	317,489,515

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FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgress
Jointly owned with Northwestern Energy, LLC, Talen Montana, LLC, Puget Sound Energy, Inc, PacifiCorp, and Avista Corporation. Respondent's 20% share of jointly owned costs is reported.
(b) Concept: ConstructionWorkInProgress
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.
(c) Concept: ConstructionWorkInProgress
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.
(d) Concept: ConstructionWorkInProgress
(e) Concept: ConstructionWorkInProgress
(f) Concept: ConstructionWorkInProgress
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.
(g) Concept: ConstructionWorkInProgress
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.
(h) Concept: ConstructionWorkInProgress
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	4,483,327,657	4,483,327,657		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	318,796,594	318,796,594		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,813,130	2,813,130		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,553,610	6,553,610		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	328,163,334	328,163,334		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(77,483,839)	(77,483,839)		
13	Cost of Removal	(15,029,629)	(15,029,629)		
14	Salvage (Credit)	2,141,632	2,141,632		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(90,371,836)	(90,371,836)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Reserve Adjustments	1,024,012	[(a)] 1,024,012		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,722,143,167	4,722,143,167		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	403,986,940	403,986,940		
21	Nuclear Production				
22	Hydraulic Production-Conventional	295,753,517	295,753,517		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,058,675,939	1,058,675,939		
25	Transmission	388,751,605	388,751,605		
26	Distribution	2,291,154,531	2,291,154,531		
27	Regional Transmission and Market Operation				

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)
28	General	283,820,635	283,820,635		
29	TOTAL (Enter Total of lines 20 thru 28)	4,722,143,167	4,722,143,167		

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation
$1M reserve credits due mainly to correction of prior year O&M decommissioning expense recorded as cost of removal in 2020.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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			[(a)] 5,140,815	1,475,098		6,615,913	
4	Additional Paid In Capital			[(b)] [(c)] 77,528,661			77,528,661	
5	SubTotal			82,670,476	1,475,098	0	84,145,574	0
6	Salmon Springs Hospitality Group							
7	Common Stock	04/09/1998		10,000			10,000	
8	Equity in Earnings			(593,516)	(361,166)		(954,682)	
9	SubTotal			(583,516)	(361,166)	0	(944,682)	0
42	Total Cost of Account 123.1 $ 77,539,661		Total	82,086,960	1,113,932	0	83,200,892	0

FOOTNOTE DATA

(a) Concept: InvestmentInSubsidiaryCompanies
Amount previously included Additional Paid In Capital.
(b) Concept: InvestmentInSubsidiaryCompanies
Amount was previously reported as part of Equity in Earnings.
(c) Concept: InvestmentInSubsidiaryCompanies
This amount was previously reported as part of Equity in Earnings but should have been Paid-in-Capital.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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)	17,886,804	25,459,349	Generation
2	Fuel Stock Expenses Undistributed (Account 152)		0	
3	Residuals and Extracted Products (Account 153)		0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	21,101,356	21,234,237	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	14,628,422	15,421,665	Generation
8	Transmission Plant (Estimated)	570,226	409,865	Transmission
9	Distribution Plant (Estimated)	8,054,839	9,890,358	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]1,875,277	[(b)]1,339,679	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	46,230,120	48,295,804	
13	Merchandise (Account 155)		0	
14	Other Materials and Supplies (Account 156)		0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)		0	
16	Stores Expense Undistributed (Account 163)	2,688,473	2,270,648	
17				
18				
19				
20	TOTAL Materials and Supplies	66,805,397	76,025,801	

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)
1	Balance-Beginning of Year	79,363	0	10,032		10,030	
2							
3	Acquired During Year:						
4	Issued (Less Withheld Allow)						
5	Returned by EPA						
6							
7							
8							
9							
10							
11							
12							
13							
14							
15	Total						
16							
17	Relinquished During Year:						
18	Charges to Account 509	909					
19	Other:						
20	Allowances Used						
21	Cost of Sales/Transfers:						
22							
23							
24							
25							
26							
27							
28	Total						
29	Balance-End of Year	78,454		10,032		10,030	
30							
31	Sales:						
32	Net Sales Proceeds(Assoc. Co.)						
33	Net Sales Proceeds (Other)						
34	Gains						
35	Losses						

Line No.	Allowances (Accounts 158.1 and 158.2) SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)
	Allowances Withheld (Acct 158.2)						
36	Balance-Beginning of Year	1,201		193		193	
37	Add: Withheld by EPA						
38	Deduct: Returned by EPA						
39	Cost of Sales	193					
40	Balance-End of Year	1,008		193		193	
41							
42	Sales						
43	Net Sales Proceeds (Assoc. Co.)						
44	Net Sales Proceeds (Other)		3				
45	Gains						
46	Losses						

Allowances (Accounts 158.1 and 158.2)						
Line No.	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	10,033		86,588		196,046	0
2						
3						
4			1,319		1,319	0
5					0	0
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18					909	0
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29	10,033		87,907		196,456	0
30						
31						
32					0	0
33					0	0
34					0	0
35					0	0
36	193		2,657		4,437	0
37					0	0
38					0	0

Allowances (Accounts 158.1 and 158.2)						
Line No.	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
39			193		386	0
40	193		2,464		4,051	0
41						
42						
43					0	0
44				2	0	5
45					0	0
46					0	0

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Allowances (Accounts 158.1 and 158.2)							
Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)
	Allowances Withheld (Acct 158.2)						
36	Balance-Beginning of Year						
37	Add: Withheld by EPA						
38	Deduct: Returned by EPA						
39	Cost of Sales						
40	Balance-End of Year						
41							
42	Sales						
43	Net Sales Proceeds (Assoc. Co.)						
44	Net Sales Proceeds (Other)						
45	Gains						
46	Losses						

Allowances (Accounts 158.1 and 158.2)						
Line No.	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1						
2						
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36						
37						
38						

Allowances (Accounts 158.1 and 158.2)						
Line No.	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Abandoned Trojan Nuclear Plant Decommissioning Costs; PGE has the authority to continue the recovery of the expense in rates until decommissioning is complete, as authorized by OPUC (Order No. 07-015, dtd 1/12/2007)	427,588,467	6,466,993		[a](11,805,232)	90,148,743
49	TOTAL	427,588,467	6,466,993		(11,805,232)	90,148,743

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: UnrecoveredPlantAndRegulatoryStudyCostsWrittenOff

$1,900,000 - Recovery of Trojan decommissioning costs included in retail prices, untildecommissioning is complete, as authorized by OPUC (Order #07-015, dtd 1/12/2007 andupdated by Order #18-464), offset in Account 407. $9,905,232 Represents refunds received from the Department of Energy (DOE) for reimbursement of Respondent's costs incurred monitoring the Independent Spent Fuel Storage Installation (ISFSI) at Trojan.

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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**				
20	Total				
21	**Generation Studies**				
22	19-081	2,209	561.7		
23	20-082	8,403	561.7		
24	20-083	13,856	561.7		
25	20-085	1,122	561.7		
26	20-086	14,823	561.7		
27	20-095	4,537	561.7		
28	21-095	20,105	561.7		
29	21-096	2,091	561.7		
30	PGEM Surplus Facility Study	569	561.7		
31	Other	275	561.7		
39	Total	67,990			
40	Grand Total	67,990		0	

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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 Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Tax Benefits Related to Book/Tax Basis Differences (Amort. period is based on the lives of the properties, approximately 25 years.)	40,909,804	13,279,584	282	11,939,575	42,249,813
2	Previously Flowed to Customers (Amort. period is based on the lives of the properties, approximately 25 years.)	15,517,511	5,039,843	283	4,531,564	16,025,790
3	Price Risk Management	124,180,180	686,676,879	254 / 555 / 547	755,607,562	55,249,497
4	Deferred Broker Settlement	972,039	56,094,169	134 / 254 / 547 / 555	57,066,209	(1)
5	Intervenor Funding (original deferral per OPUC Order No. 03-388 dtd 7/2/2003)	583,115	315,802	421	397	898,520
6	Coyote Springs Major Maintenance Accrual LTSA (per OPUC GRC 95-1216, dtd 11/20/1995)	2,874,499	2,952,307	553	1,980,948	3,845,858
7	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	5,198	275,463	182.3 / 254 / 421 / 908	218,502	62,159
8	Glass Insulator Deferral (per OPUC Order No. 10-478 dtd 12/17/2010; UE 215 First Revenue Requirement Stipulation) Amortization period: 56 years	5,398,895	0	571	106,333	5,292,562
9	Pension Funding Postretirement Funding (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	239,618,346	0	219	108,118,775	131,499,571
10	Boardman Decommissioning Balancing (Per Advice No. 11-07 dtd 05/27/2011)	(51,131)	284,345	242 / 431 / 456	233,214	0
11	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17) (Amortization period 1/1/2018-12/31/2021)	258,694	5,788,198	407.3 / 431	4,760,409	1,286,483
12	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019) (Amortization period 1/1/2020-12/31/2020)	0	2,362,459	182.3 / 232 / 254 / 407.3 / 431 / 903 / 908 / 921 / 925	2,362,459	0
13	CET Deferral (2014-2018 vintages) (amortization per OPUC Order No. 17-511, dtd 12/18/17) (Amortization period 01/01/2018-12/31/2022)	6,341,426	269,235	182.3 / 903	3,221,886	3,388,775
14	Schedule 110 Energy Efficiency (per OPUC Advice No. 10-01)	10,460	1,642,077	232 / 407.3 / 431 / 921 / 925	1,652,536	1
15	Deferred Cost - Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708) (Amortization period 1/1/2020-12/31/2021)	259,746	4,317,070	182.3 / 232 / 254 / 407.3 / 421 / 431 / 909 / 921 / 925	4,584,929	(8,113)
16	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708) (Amortization period 1/1/2020-12/31/2021)	931,228	4,957,957	143 / 182.3 / 232 / 254 / 407.3 / 431 / 909	5,774,047	115,138

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 Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
17	Gresham Privilege Tax Collection Deferral (Advice No. 17-05, Schedule 134, dtd 02/24/17) (Amortization period 1/1/2018-12/31/2022)	3,445,419	1,373,151	182.3 / 407.3	3,030,028	1,788,542
18	Portland Harbor Environmental Remediation Deferral (Per OPUC Order No. 17-071, Docket No. UM1789, dtd 03/02/17)	22,316,939	8,613,931	107 / 143 / 254 / 421	3,400,638	27,530,232
19	Non-Residential Sch 123 SNA Deferral-2020 (Reauthorized Advice No. 20-31, dtd 11/13/2020)	9,497,934	11,301,856	182.3	10,399,895	10,399,895
20	Lost Revenue Recovery-2019 (Per OPUC Order No. 16-359 dtd 9/26/2016) (Amortization period 1/1/2021-12/31/2021)	325,100	3,281	182.3 / 456	278,378	50,003
21	Interest Rate Swap (Interest Rate Hedges for Long Term Debt Amortization period: 30 years)	4,427,535	0	428.1	156,264	4,271,271
22	Transportation Electrification Prgm (Per UM 1811, Order No. 18-124, dtd 4/12/2018)	425,043	731,658	143 / 232 / 908 / 920 / 921 / 925	73,363	1,083,338
23	EV Charging (Non-Residential) (Per UM 2003, Order No. 20-381, dtd 10/27/2020)	78,717	48,719	143	11,080	116,356
24	EV Charging (Residential) (Per UM 2003, Order No. 202-381, dtd 10/27/2020)	67,092	269,367	232	11,874	324,585
25	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017) (Amortization period 1/1/2018-12/31/2021)	783,789	6,676,171	182.3 / 232 / 254 / 407.3 / 421 / 431 / 921 / 925	7,459,958	2
26	Community Solar (Per UM-1977, OPUC Order No. 18-477, dtd 12/19/2018)	1,133,026	2,224,437	182.3 / 407.3	1,387,346	1,970,117
27	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order No. 10-198 dtd 5/28/2010) (Reauthorized OPUC Order No. 15-185 dtd 6/09/2015)	0	6,884,692	190 / 254 / 282 / 283 / 921 / 925	6,884,692	0
28	Residential Sch123 SNA Deferral-2019 (Reauthorized Advice No. 16-23, dtd 11/23/2016)	13,362,905	4,763,548	456	19,283,844	(1,157,391)
29	Non-residential Sch 123 SNA Deferral 2019 (reauthorized Advice No. 16-23, dtd 11/23/2016)	4,257,673	23,469	456	3,012,913	1,268,229
30	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020)	11,605	419,052	182.3	145,698	284,959
31	Wheatridge Renewable Energy Farm (Per UE-370, Order No. 20-279, dtd 8/26/2020)	1,583,614	0	553	52,936	1,530,678
32	Emergency Wildfire (Per UM-2115, Order No. 20-389, dtd 10/27/2020)	15,460,221	42,241,518	182.3 / 232 / 456 / 521 / 539 / 545 / 571 / 593 / 921 / 925	11,938,683	45,763,056

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 Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
33	COVID-19 (Per UM-2064, Order No. 20-376, dtd 10/27/2020)	10,238,619	33,807,173	232 / 421 / 431 / 557 / 593 / 921 / 925	7,660,529	36,385,263
34	Oregon Commercial Activity Tax (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020)	(18,768)	18,066,960	254 / 407.4 / 431	18,130,156	(81,964)
35	OPUC Fee Deferral (Per UM-2046, Order No. 20-411, dtd 11/05/2020)	1,113,751	1,903,378	165	261,104	2,756,025
36	Emergency Restoration Costs (Per UM 2156, filing dtd 2/15/2021)	0	132,671,829	107 / 108 / 186 / 232 / 421 / 447 / 557 / 560 / 571 / 580 / 581 / 582 / 583 / 588 / 590 / 591 / 592 / 593 / 594 / 903 / 905 / 909 / 921 / 925 / 930.1	64,233,555	68,438,274
37	Non-Residential Sch. 123 SNA Deferral-2021 (Reauthorized Advice No. 20-31, dtd 11/13/2020)	0	7,400,159	421 / 456	635,379	6,764,780
38	Direct Access 2021 (Per UM-1301, Order No. 21-034, dtd 1/28/2021)	0	261,852		0	261,852
39	Level III Storm (Per UE-335, Order No. 18-464, dtd 12/18/2018)	0	6,341,160	449.1	6,341,160	0
40	BPSC Microgrid Storage (UM 2113, Order No. 20-370)	0	897,461		0	897,461
41	Independent Evaluator (UM-2184)	0	16,150		0	16,150
42	PCAM 2021 (UE-395)	0	34,460,785	555	5,726,243	28,734,542
43	Regional Power Act (RPA)	0	1,321,083		0	1,321,083
44	Residential Sch123 SNA Deferral-2018 (Reauthorized Advice No. 16-23 dtd 11/23/2016 Amortization period 1/1/2020-12/31/2020)	183,823	190,309	242 / 256	374,132	0
45	Residential Sch123 SNA Deferral-2020 (Reauthorized Advice No. 16-23, dtd 11/23/2016)	40,028	0	254	40,028	0
44	TOTAL	526,544,075	1,107,168,537		1,133,089,221	500,623,391

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Misc. Undistributed Charges	292,264	123,905	Various	175,443	240,726
2	Net Co-owner / Trust Contribution	320,582	41,873,762	Various	42,057,672	136,672
3	Deferred Revolving Credit Agreement Fees (amort through Sept 2026)	950,116	1,853,386	431	372,275	2,431,227
4	Dispatchable Generation (various amort periods from 2011 and extending through 2030)	9,567,667	1,456,988	903	3,348,614	7,676,041
5	Utility Property Sales - Selling Expenses	76,278	1,715,114	Various	1,424,326	367,066
47	Miscellaneous Work in Progress	34,304				86,185
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	11,241,211				10,937,917

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	319,689,145	302,579,496
3	Regulatory Liabilities	21,459,037	38,298,735
4	Employee Benefits	136,517,004	114,768,148
5	Price Risk Management	41,506,877	37,933,070
6	Tax Credits & NOL's	77,041,984	99,322,362
7	Other	12,016,102	[a]8,664,427
8	TOTAL Electric (Enter Total of lines 2 thru 7)	608,230,149	601,566,238
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	0	0
17.1	Other (Specify)	9,409,220	[b]9,698,967
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	617,639,369	611,265,205

Notes

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 7 - Other	**Ending Balance 12/31/2020**	**Ending Balance 12/31/2021**
Bad Debt Expense	$4,301,617	$7,266,534
Deferred Revenue	1,362,280	1,107,805
Nuclear Decommissioning Trust	8,492,158	9,227,883
Renewable Energy Development	3,653,395	977,419
Finance Lease Liability	(12,016,724)	(11,444,856)
Miscellaneous	6,223,377	1,529,644
Total Line 7 - Other	**$12,016,103**	**$8,664,427**

(b) Concept: AccumulatedDeferredIncomeTaxes

Line 17 - Other Non-Utility	Ending Balance 12/31/2020	Ending Balance 12/31/2021
Property Related	$9,409,495	$9,555,916
Employee Benefits	-275	143,051
Total Line 17 - Other Non-Utility	$9,409,220	$9,698,967

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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			89,410,612	
6	Total	160,000,000			89,410,612	1,245,720,283
7	Preferred Stock (Account 204)					
8	Preferred Stock	30,000,000				
11	Total	30,000,000				0
1	Capital Stock (Accounts 201 and 204) - Data Conversion					
2						
3						
4						
5	Total					

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				
6				
7				
8				
11				
1				
2				
3				
4				
5				

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2022-04-25	Year/Period of Report End of: 2021/ Q4

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	49,120
11.1	Increase/Decrease on sale/cancellation of capital stock	(49,120)
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	(49,120)
12	Ending Balance Amount	0
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	12,428,737
15.1	Tax benefits related to stock compensation plans	1
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	1
16	Ending Balance Amount	12,428,738
17	Historical Data - Other Paid in Capital	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	18,789,718

CAPITAL STOCK EXPENSE (Account 214)

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	23,113,532
22	TOTAL	23,113,532

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	9.31% MTN SERIES DUE 08-11-2021	221	20,000,000		176,577	0	0
3	6.875% SERIES VI DUE 8-1-2033	221	50,000,000		519,257	0	437,500
4	6.26% SERIES DUE 5-1-2031	221	100,000,000		723,856	0	0
5	6.31% SERIES DUE 5-1-2036	221	175,000,000		1,270,565	0	0
6	5.80% SERIES DUE 6-1-2039	221	170,000,000		1,460,968	0	0
7	5.81% SERIES DUE 10-1-2037	221	130,000,000		1,109,574	0	517,518
8	$150mm 5.43% SERIES DUE 5-3-2040 - Order No.09-245 - 6/22/2009	221	150,000,000		1,034,284	0	0
9	$150mm 4.47% SERIES DUE 6/15/2044 - Order No.13-098 - 3/26/2013	221	150,000,000		1,113,047	0	0
10	$75mm 4.47% SERIES DUE 8/14/2043 - Order No.13-098 - 3/26/2013	221	75,000,000		558,740	0	0
11	$50mm 4.84% SERIES DUE 12/15/2048 - Order No.13-098 - 3/26/2013	221	50,000,000		311,154	0	0
12	$105mm 4.74% SERIES DUE 11/15/2042 - Order No.13-098 - 3/26/2013	221	105,000,000		652,029	0	0
13	$100mm 4.39% SERIES DUE 8-15-2045 - Order No.14-145 - 4/29/2015	221	100,000,000		645,383	0	0
14	$100mm 4.44% SERIES DUE 10-15-2046 - Order No.14-145 - 4/29/2015	221	100,000,000		625,030	0	0
15	$80mm 3.51% SERIES DUE 11-15-2024 - Order No.14-145 - 4/29/2015	221	80,000,000		501,502	0	0
16	$75mm 3.55% SERIES DUE 1/15/2030 - Order No.14-399 - 11/12/2014	221	75,000,000		325,295	0	0
17	$70mm 3.50% SERIES DUE 5/15/2035 - Order No.14-399 - 11/12/2014	221	70,000,000		305,128	0	0
18	$140mm 2.51% SERIES DUE 1/6/2021 - Order No.14-399 - 11/12/2014	221	140,000,000		592,932	0	0
19	$150mm 3.98% Series Due 11/21/2047 - Order No.16-152 - 4/21/2016	221	150,000,000		(99,510)	0	0
20	$75mm 3.98% Series Due 8/3/2048 - Order No.16-152 - 4/21/2016	221	75,000,000		(44,757)	0	0
21	$75mm 4.47 Series Due 12/11/2048 - Order No.16-152 - 4/21/2016	221	75,000,000		336,938	0	0
22	$200mm 4.3% Series Due 4-11-2049 - Order No.18-453 - 12/4/2018	221	200,000,000		860,461	0	0
23	$110mm 3.34%% Series Due 10-15-2049 - Order No.18-453 - 12/4/2018	221	110,000,000		477,767	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)
24	$160mm 3.34% Series Due 1-15-2050 - Order No.18-453 - 12/4/2018	221	160,000,000		694,934	0	0
25	$200mm 3.15% Series Due 4-1-2030 - Order No.18-453 - 12/4/2018	221	200,000,000		862,049	0	0
26	$160mm 1.84% Series Due 12-10-2027 - Order No.20-169 - 5/22/2020	221	160,000,000		645,816	0	0
27	$70mm 2.32% Series Due 12-10-2032 - Order No.20-169 - 5/22/2020	221	70,000,000		278,000	0	0
28	$100mm 1.82% Series Due 9-30-2028 - Order No.20-169 - 5/22/2020	221	100,000,000		452,981	0	0
29	$50mm 2.10% Series Due 9-30-2031 - Order No.20-169 - 5/22/2020	221	50,000,000		226,490	0	0
30	$100mm 2.20% Series Due 1-15-2034 - Order No.20-169 - 5/22/2020	221	100,000,000		452,981	0	0
31	$150mm 2.97% Series Due 9-30-2051 - Order No.20-169 - 5/22/2020	221	150,000,000		679,471	0	0
32	$97.8mm CITY FORSYTH 2.125% DUE 05-01-2033 - Order No.09-099 - 3/26/2009	221	97,800,000		528,702	(1,956,000)	0
33	$21.0mm CITY FORSYTH 2.375% DUE 05-01-2033 - Order No.09-099 - 3/26/2009	221	21,000,000		97,594	0	0
34	Subtotal		3,458,800,000		18,375,238	(1,956,000)	955,018
35	Reacquired Bonds (Account 222)						
36							
37							
38							
39	Subtotal						
40	Advances from Associated Companies (Account 223)						
41							
42							
43							
44	Subtotal						
45	Other Long Term Debt (Account 224)						
46							
47							
48							
49	Subtotal						
33	TOTAL		3,458,800,000				

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	08/12/1991	08/11/2021	08/12/1991	08/11/2021	0	1,143,054
3	08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500
4	05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000
5	05/16/2007	05/01/2036	05/16/2007	05/01/2036	175,000,000	11,042,500
6	09/19/2007	06/01/2039	09/19/2007	06/01/2039	170,000,000	9,860,000
7	09/19/2009	10/01/2037	09/19/2009	10/01/2037	130,000,000	7,553,000
8	11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000
9	06/07/2013	06/15/2044	06/07/2013	06/15/2044	150,000,000	6,705,000
10	08/29/2013	08/14/2043	08/29/2013	08/14/2043	75,000,000	3,352,500
11	12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000
12	11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000
13	08/15/2014	08/15/2045	08/15/2014	08/15/2045	100,000,000	4,390,000
14	10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000
15	11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000
16	01/15/2015	01/15/2030	01/15/2015	01/15/2030	75,000,000	2,662,500
17	05/15/2015	05/15/2035	05/15/2015	05/15/2035	70,000,000	2,450,000
18	01/06/2016	01/06/2021	01/06/2016	01/06/2021	0	48,806
19	11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000
20	08/03/2017	08/03/2048	08/03/2017	08/03/2048	75,000,000	2,985,000
21	12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	3,352,500
22	04/19/2019	04/11/2049	04/19/2019	04/11/2049	200,000,000	8,600,000
23	10/15/2019	10/15/2049	10/15/2019	10/15/2049	110,000,000	3,674,000
24	11/15/2019	01/15/2050	11/15/2019	01/15/2050	160,000,000	5,344,000
25	04/27/2020	04/01/2030	04/27/2020	04/01/2030	200,000,000	6,300,000
26	12/10/2020	12/10/2027	12/10/2020	12/10/2027	160,000,000	2,944,000
27	12/10/2020	12/10/2032	12/10/2020	12/01/2032	70,000,000	1,624,000
28	09/30/2021	09/30/2028	09/30/2021	09/30/2028	100,000,000	455,000
29	09/30/2021	09/30/2031	09/30/2021	09/30/2031	50,000,000	262,500
30	09/30/2021	01/15/2034	09/30/2021	01/15/2034	100,000,000	550,000
31	09/30/2021	09/30/2051	09/30/2021	09/30/2051	150,000,000	1,116,115
32	03/11/2020	05/01/2033	03/11/2020	05/01/2033	97,800,000	1,942,417
33	03/11/2020	05/01/2033	03/11/2020	05/01/2033	21,000,000	498,750
34					3,298,800,000	127,313,142
35						
36						
37						

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)
38						
39					0	
40						
41						
42						
43						
44					0	
45						
46						
47						
48						
49					0	
33					3,298,800,000	127,313,142

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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)	245,390,754
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion, & Amortization	39,868,307
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	(106,031,370)
11	Regulatory Credits	69,858,723
12	Other (See Footnote)	[a](49,835,489)
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion, & Amortization	25,132,504
16	Regulatory Debits	(28,882,810)
17	Miscellaneous	[b]532,120
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion, & Amortization	118,468,663
21	State & Local Tax Deduction	13,886,899
22	Other (See Footnote)	[c]4,533,314
27	Federal Tax Net Income	65,580,235
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	13,406,340
30	PTC C/F	(10,329,935)
31	RTA Federal Tax Adjustment	227,860
32	Other Items Affecting Tax	(112,012)
33	Total Federal Income Tax - PGE	3,192,253

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Line 12 - Deductions Recorded on Books Not Deducted for Return	
Qualified NDT	2,438,958
Meals & Entertainment	300,000
Political Activity	1,385,189
Bad Debts	10,595,359
Fines and Penalties	151,133
Employee Benefits	(83,818,723)
Federal Tax Expense	3,677,168
Orion Contingent Royalty Payments	(451,785)
Tax Finance Lease	2,372,721
Unamortized loss on reacquired debt	1,588,954
State & Local Tax Expense	18,724,574
Deferred Revenue	(1,168,787)
Wheatridge RECs	(4,516,317)
Miscellaneous	(1,113,932)
Total Other	(49,835,489)

(b) Concept: IncomeRecordedOnBooksNotIncludedInReturn

Line 17 - Income Recorded on Books Not Included in Return	
Key Man Insurance Proceeds	3,063,217
OCI	(1,622,070)
Miscellaneous	(909,028)
Total Other	532,120

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Line 22 - Deductions on Return Not Charged Against Book Income	
Dividend Received Deduction	32,000
Prepaid	(2,575,851)
Renewable Energy Initiatives	6,327,939
Property Tax	854,377
Miscellaneous	(105,151)
Total Other	4,533,314

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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 Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)
1	Federal:	Federal Tax	Federal			
2	FERC Resale/Coord	Federal Tax	Federal		218,735	
3	Income Tax	Federal Tax	Federal			1,587,059
4	Foreign Insurance Excise Tax	Federal Tax	Federal			
5	FICA (Employer Share)	Federal Tax	Federal		14,518,371	
6	Unemployment	Federal Tax	Federal		1,895	
7	Power License	Federal Tax	Federal		262,130	(255,024)
8	State of Montana:	State Tax	Federal			
9	Income Tax	Income Tax	Montana			(425,317)
10	Electric Energy Producers Tax	Other License And Fees Tax	Montana		323,923	
11	Property Taxes	Property Tax	Montana		3,927,119	
12	State of Oregon:	State Tax	Oregon			
13	Corp Excise Tax and CAT	Excise Tax	Oregon		243,008	3,149,315
14	Property Taxes	Property Tax	Oregon		(2,358)	37,295,240
15	City Taxes & Licenses	Franchise Tax	Oregon		3,685,110	
16	Public Utility Comm Fees	Other Taxes and Fees	Oregon			
17	Department of Energy	Other Taxes and Fees	Oregon			1,113,304
18	Department of Enviro Quality	Other Taxes and Fees	Oregon		667,374	
19	Unemployment	Payroll Tax	Oregon		30,019	
20	Water Power Fee	Other Taxes and Fees	Oregon			(1,415)
21	Transportation Tax	Payroll Tax	Oregon		550,481	
22	Workers Comp Assessment	Payroll Tax	Oregon			
23	County & City Income Tax	Income Tax	Oregon			682,832
24	State of Washington:	State Tax	Washington			
25	Property Taxes	Property Tax	Washington		2,264,117	
26	Sales Tax	Sales And Use Tax	Washington			
27	State of California:	State Tax	California			
28	Corporate Franchise Tax	Franchise Tax	California			(1,274,299)
40	TOTAL				26,689,924	41,871,695

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 Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED Electric (Account 408.1, 409.1) (l)
1				0		
2	1,190,619	1,127,483		281,871		
3	3,192,337	3,800,000		0	2,194,722	7,528,447
4				0		70,826
5	26,323,992	25,487,456		15,354,907		14,268,549
6	136,914	135,260		3,549		73,297
7	2,931,486	3,024,371		276,317	(147,952)	
8				0		
9	108,371	100,000	113,320	0	(547,008)	152,870
10	493,082	632,130		184,875		287,941
11	6,752,070	7,400,853		3,278,336		5,206,001
12				0		
13	12,849,610	11,124,968		243,008	1,424,673	14,511,721
14	72,513,662	73,369,310	1,535,279	0	36,617,967	68,983,883
15	48,070,263	48,131,594	(2)	3,623,777		48,271,948
16	8,089,546	8,089,546		0		
17	2,377,602	2,528,598	3,771	0	1,260,529	2,377,602
18	(85,856)	479,480		102,038		
19	1,948,155	2,165,089		(186,915)		1,024,996
20	616,988	1,352,499		0	734,096	
21	2,084,063	2,131,863		502,681		1,109,653
22	279,369	279,369		0		146,579
23	607,964	590,000		0	664,868	723,557
24				0		
25	2,068,163	2,076,216	13,400	2,269,464		2,068,163
26				0		
27				0		
28	261,485	150,000		0	(1,385,784)	288,369
40	192,809,885	194,176,085	1,665,768	25,933,908	40,816,111	167,094,402

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR			
Line No.	DISTRIBUTION OF TAXES CHARGED Extraordinary Items (Account 409.3) (m)	DISTRIBUTION OF TAXES CHARGED Adjustment to Ret. Earnings (Account 439) (n)	DISTRIBUTION OF TAXES CHARGED Other (o)
1			
2			1,190,619
3			(4,336,110)
4			(70,826)
5			12,055,443
6			63,617
7			2,931,486
8			
9			(44,499)
10			205,141
11			1,546,069
12			
13			(1,662,111)
14			3,529,779
15			(201,685)
16			8,089,546
17			
18			(85,856)
19			923,159
20			616,988
21			974,410
22			132,790
23			(115,593)
24			
25			
26			
27			
28			(26,884)
40		0	25,715,483

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

OTHER DEFERRED CREDITS (Account 253)

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Tenant security deposits	160,000				160,000
2	Deferred Liability for Transferred Non-Qualified Plan Benefits	535,517	421	18,997		516,520
3	Reserve for Environmental Remediation Costs	4,000,000				4,000,000
4	Clean Fuels Program OPUC 17-250 and 17-512	10,667,879	232, 926	2,595,792	6,832,505	14,904,592
47	TOTAL	15,363,396		2,614,789	6,832,505	19,581,112

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)
1	Account 282					
2	Electric	819,161,947	85,078,548	71,343,526		
3	Gas					
4	Other (Specify)					
5	Total (Total of lines 2 thru 4)	819,161,947	85,078,548	71,343,526		
6						
7						
8						
9	TOTAL Account 282 (Total of Lines 5 thru 8)	819,161,947	85,078,548	71,343,526		
10	Classification of TOTAL					
11	Federal Income Tax	653,894,117	57,187,334	43,201,479		
12	State Income Tax	154,758,980	25,750,837	16,156,708		
13	Local Income Tax	10,508,850	2,140,377	11,985,339		

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		16,833,597		18,173,606	834,236,978
3					0
4					0
5		16,833,597		18,173,606	834,236,978
6					
7					
8					0
9		16,833,597		18,173,606	834,236,978
10					
11		11,830,459		12,638,834	668,688,347
12		4,140,943		4,294,107	164,506,273
13		862,195		1,240,665	1,042,358

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)
1	Account 283					
2	Electric					
3	Property Related	15,517,470				
4	Price Risk Management	12,404,111	61,613,181	37,001,197		
5	[a] Regulatory Assets	[c]128,533,217	84,408,986	99,039,376		
6	Regulatory Liabilities					
7	[b] Other	[d]15,068,654	236,008	745,414		
9	TOTAL Electric (Total of lines 3 thru 8)	171,523,452	146,258,175	136,785,987		
10	Gas					
11						
12						
13						
14						
15						
16						
17	TOTAL Gas (Total of lines 11 thru 16)					
18	TOTAL Other	[e]1,793,866			6,204,569	967,768
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	173,317,318	146,258,175	136,785,987	6,204,569	967,768
20	Classification of TOTAL					
21	Federal Income Tax	121,450,917	102,697,329	93,848,613	4,421,922	640,799
22	State Income Tax	48,623,914	41,103,403	37,561,807	1,746,238	256,453
23	Local Income Tax	3,242,487	2,457,443	5,375,567	36,409	70,516

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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					
3	254	6,257,060	182.3	6,438,879	15,699,289
4		2,407,538		3,380,768	37,989,325
5		6,932,084		7,739,088	114,709,831
6					
7		7,424,219		8,278,429	15,413,458
9		23,020,901		25,837,164	183,811,903
10					
11					
12					
13					
14					
15					
16					
17					
18	254	337,477	182.3	482,805	7,175,995
19		23,358,378		26,319,969	190,987,898
20					
21		6,313,274		4,860,044	132,627,526
22		2,205,639		1,624,000	53,073,656
23		14,839,465		19,835,925	5,286,716

NOTES

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Beginning Balance Ending Balance ASC 715 Pension & Post Retirement 58,539,486 65,895,041 ASC 980 Mark-to-Market 26,133,312 34,149,547 Miscellaneous 14,075,100 7,217,119 Decoupling (231,530) 7,118,420 CET Deferral 2,331,247 1,504,124 Feed in Tariff (FIT) (14,225) (31,284) Portland Harbor (PHERA) 2,749,113 5,715,712 Covid-19 - 2,777,977 Wildfire - 4,186,561 Subtotal Regulatory Assets 103,582,503 128,533,217

(b) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Beginning BalanceEnding Balance Prepaid Property Tax 8,285,585 9,426,089 Unamortized Loss on Reacquired Debt 5,997,340 5,642,565 Subtotal Other 14,282,925 15,068,654

(c) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning Balance	**Ending Balance**
ASC 715 Pension & Post Retirement	65,895,041	36,418,955
ASC 980 Mark-to-Market	34,149,547	15,301,410
Miscellaneous	7,217,119	(12,306,613)
Decoupling	7,118,420	1,775,748
CET Deferral	1,504,124	692,665
Feed in Tariff (FIT)	(31,284)	17,920,502
Portland Harbor (PHERA)	5,715,712	6,970,309
Covid-19	2,777,977	9,918,578
Wildfire	4,186,561	12,004,577
Storm Deferral	-	18,055,637
PCAM Deferral	-	7,958,063
Subtotal Regulatory Assets	**128,533,217**	**114,709,831**

(d) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning Balance	**Ending Balance**
Prepaid Property Tax	9,426,089	9,699,503
Unamortized Loss on Reacquired Debt	5,642,565	5,242,537
Local Flow-Through Deferred Income Tax	–	471,418
Other	–	–
Subtotal Other	**15,068,654**	**15,413,458**

(e) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning Balance	**Ending Balance**
Other	1,075,812	3,750,209
Trust Owned Life Insurance	718,054	417,060
Decoupling	–	3,008,726
Subtotal Other	**1,793,866**	**7,175,995**

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Income Taxes	295,331,509	182.3 / 190 / 236 / 254	64,433,318	35,701,636	266,599,827
2	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001)	1,920,519	236 / 254 / 407.4	3,920,410	3,018,028	1,018,137
3	Boardman Severance (Advice No.14-18, dtd 11/3/2014)	6,674,303	456 / 925	1,562,194	32,715	5,144,824
4	Asset Retirement Obligations: Balancing Account	36,835,543	108 / 228.2 / 254 / 407.3 / 410.1 / 456 / 925	43,909,589	50,473,818	43,399,772
5	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	1,235,397	254	3,750,559	4,119,272	1,604,110
6	Colstrip Major Maintenance Deferral (Per OPUC UE-319, Order No. 17-511, dtd 12/18/17)	5,246,879	254	3,434,516	2,615,665	4,428,028
7	Port Westward 1 Major Maint Deferral (Per OPUC UE 262, Order No. 13-459, dtd 12/9/2013)	2,233,971	254	2,151,957	3,330,738	3,412,752
8	Port Westward 2 Major Maintenance Deferral (Per OPUC 2015 GRC Docket UE-283, OPUC Order No.14-422, dtd 12/4/2014)	2,953,790	449.1	0	826,852	3,780,642
9	Zero Interest Program Loan Repayments (Per Advice No. 05-19 dtd 12/20/2005)	2,106,765	254 / 431 / 407.4	3,367,097	1,389,363	129,031
10	Schedule 110 Energy Efficiency - Balancing Account (Per Advice No. 07-25 dtd 5/20/2008)	0		0	965,460	965,460
11	Sunway 3 Investment Deferral (Per UM 1480 dtd 4/01/2010; Amortization over 20 years commencing 2010)	431,950	407.4	45,480	0	386,470
12	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017) (Amortization period 1/1/2019-12/31/2019)	6,888,426	182.2	6,609,990	75,630	354,066
13	PRC Acquisition (Per OPUC UE-283 Final GRC Order No.14-422, dtd 12/04/2014, Second Partial Stipulation dtd 9/2/2014)	3,680,540	128	1,582	4,562	3,683,520
14	Deferred Broker Settlement	0	182.3	29,118,662	40,628,590	11,509,928
15	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order 10-198 dtd 5/28/2010 reauthorized OPUC Order 15-185 dtd 6/09/2015)	4,544,115	182.3 / 254 / 407.3	14,141,160	16,598,404	7,001,359
16	Portland Harbor Environmental Deferral (Per OPUC Order No. 17-071, UM-1789 dtd 03/02/17)	(2,766)	182.3	1	2,767	0
17	Price Risk Management	18,351,934	182.3	273,418,178	310,518,865	55,452,621
18	Monet NVPC QF Deferral-2019 (Per UE-335 NVPC Stipulation, OPUC Order No. 18-405)	3,403,653	254 / 407.4 / 555	5,346,695	1,943,043	1
19	Research & Development Tax Credits (Per UM-1991, OPUC Order No. 18-464 dtd 12/14/2018)	5,458,057	190 / 236 / 254 / 410.1 / 411.1 / 923	10,749,459	8,061,497	2,770,095

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
20	Postretirement Plans (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	3,275,373	219 / 926	1,019,570	7,646,377	9,902,180
21	Lease Obligation Balancing Account	1,156,804	547 / 555	1,388,771	139,624	(92,343)
22	Direct Access Deferral - 2019 (Per UM-1301, Order No. 19-045 dated 12/30/2019)	196,377	182.3	196,725	348	0
23	Direct Access Deferral - 2020 (Per UM-1301, Order No. 21-034 dated 1/28/2021)	400,316	254 / 431 / 447	664,827	270,024	5,513
24	OCAT (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020)	0	182.3	5,970,330	6,741,293	770,963
25	Monet NVPC QF Deferral 2020 (Per UM-1988, Order No. 19-441 dtd 12/20/2019)	1,813,776	254 / 407.4 / 555	659,649	1,163,034	2,317,161
26	Residual Account	(82,818)		0	82,818	0
27	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019) (Amortization period 1/1/2020-12/31/2020)	2,285,454	182.3 / 254 / 407.3 / 431	3,721,524	2,984,330	1,548,260
28	Residential Sch123 SNA Deferral-2020 (Reauthorized Advice No. 20-31, dtd 11/13/2020)	15,075,242	182.3 / 242 / 449.1	17,956,136	2,880,894	0
29	Deferred Cost - Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708) (Amortization period 1/1/2018-12/31/2021)	0	182.3	595,924	1,441,120	845,196
30	Residential Sch123 SNA Deferral-2021 (Reauthorized Advice No. 20-31, dtd 11/13/2020)	0	431 / 449.1	19,579,900	19,579,898	(2)
31	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708) (Amortization period 1/1/2020-12/31/2021)	0	182.3	312,747	271,103	(41,644)
32	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017) (Amortization period 1/1/2018-12/31/2021)	0	182.3 / 254	1,816,748	3,043,231	1,226,483
33	Residential Sch123 SNA Deferral-2019 (Reauthorized Advice No. 16-23, dtd 11/23/2016)	0		0	801,183	801,183
34	Wheatridge RECs	0		0	4,516,317	4,516,317
41	TOTAL	421,415,109		519,843,698	531,868,499	433,439,910

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	1,056,368,675	969,909,454	7,978,099	7,756,251	800,372	791,119
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[(a)]691,317,312	[(n)]619,175,770	6,555,280	6,173,372	111,369	110,654
5	Large (or Ind.) (See Instr. 4)	[(b)]279,876,046	[(o)]246,051,284	3,713,680	3,445,801	268	267
6	(444) Public Street and Highway Lighting	11,922,891	10,945,945	48,995	48,379	200	197
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,039,484,924	1,846,082,453	18,296,054	17,423,803	912,209	902,237
11	(447) Sales for Resale	[(c)]287,282,619	184,596,850	6,483,976	6,442,580	40	40
12	TOTAL Sales of Electricity	2,326,767,543	2,030,679,303	24,780,030	23,866,383	912,249	902,277
13	(Less) (449.1) Provision for Rate Refunds	17,402,956	(5,767,072)				
14	TOTAL Revenues Before Prov. for Refunds	2,309,364,587	2,036,446,375	24,780,030	23,866,383	912,249	902,277
15	Other Operating Revenues						
16	(450) Forfeited Discounts	1,384,370	1,510,490				
17	(451) Miscellaneous Service Revenues	[(d)]629,537	[(p)]917,276				
18	(453) Sales of Water and Water Power	(6,587)	(20,340)				
19	(454) Rent from Electric Property	15,760,270	13,829,360				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(e)] [(f)] [(g)] [(h)] [(i)] [(j)] [(k)] [(l)] [(m)]77,743,873	[(q)]94,787,137				
22	(456.1) Revenues from Transmission of Electricity of Others	10,278,316	9,742,070				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	105,789,779	120,765,993				

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)
27	TOTAL Electric Operating Revenues	2,415,154,366	2,157,212,368				

Line12, column (b) includes $ 20,543,000 of unbilled revenues.
Line12, column (d) includes 138,369 MWH relating to unbilled revenues

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $17,612,608 in revenue related to the delivery of 589,500 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregons electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utilitys remaining energy customers. For 2021, 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 $29,706,344 in revenue related to the delivery of 1,646,921 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2021, 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: SalesForResale

(d) 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 Charges
Meter Test Charges
NWCPUD Scheduling
Reconnect Charges
Returned Check Charges

This note applies to Line 17, column (b).

(e) Concept: OtherElectricRevenue

Line 21

Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
PW2 - Major Maint Deferral	-826853.04
RPA Balancing	65059040.1
Steam Sales	2562812.2
Transmission Resale	4712104.37
Gas Resale	9531756.11
ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

(f) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
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ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

(g) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
PW2 - Major Maint Deferral	-826853.04
RPA Balancing	65059040.1
Steam Sales	2562812.2
Transmission Resale	4712104.37
Gas Resale	9531756.11
ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

(h) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
PW2 - Major Maint Deferral	-826853.04
RPA Balancing	65059040.1
Steam Sales	2562812.2
Transmission Resale	4712104.37
Gas Resale	9531756.11
ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

(i) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
PW2 - Major Maint Deferral	-826853.04
RPA Balancing	65059040.1
Steam Sales	2562812.2
Transmission Resale	4712104.37
Gas Resale	9531756.11
ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

(j) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	(183,614)
Boardman Severance	1,529,479
Carty Major Maintenance Deferral	(368,713)
Colstrip - Major Maint Accrual/Defr	818,852
Hydro License Implementation and Compliance	950,859
Lost Revenue Recovery	(277,439)
MCI Metro	4,515,841
Other	1,146,791
PW1 - Major Maint Deferral	(1,178,781)
PW2 - Major Maint Deferral	(826,853)
RPA Balancing	65,059,040
Steam Sales	2,562,812
Transmission Resale	4,712,104
Gas Resale	9,531,756
ETO Management	23,855
Sch. 7 Norm Adj	(14,265,080)
Sch. 32 Norm Adj	2,794,968
Sch. 83 Norm Adj	499,489
Accumulated ARO Boardman	520,820
General Parks & Recreation	3,168
Boardman Inventory Write-Off	174,518
Grand Total	77,743,873

(k) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	(183,614)
Boardman Severance	1,529,479
Carty Major Maintenance Deferral	(368,713)
Colstrip - Major Maint Accrual/Defr	818,852
Hydro License Implementation and Compliance	950,859
Lost Revenue Recovery	(277,439)
MCI Metro	4,515,841
Other	1,146,791
PW1 - Major Maint Deferral	(1,178,781)
PW2 - Major Maint Deferral	(826,853)
RPA Balancing	65,059,040
Steam Sales	2,562,812
Transmission Resale	4,712,104
Gas Resale	9,531,756
ETO Management	23,855
Sch. 7 Norm Adj	(14,265,080)
Sch. 32 Norm Adj	2,794,968
Sch. 83 Norm Adj	499,489
Accumulated ARO Boardman	520,820
General Parks & Recreation	3,168
Boardman Inventory Write-Off	174,518
Grand Total	77,743,873

(l) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	(183,614)
Boardman Severance	1,529,479
Carty Major Maintenance Deferral	(368,713)
Colstrip - Major Maint Accrual/Defr	818,852
Hydro License Implementation and Compliance	950,859
Lost Revenue Recovery	(277,439)
MCI Metro	4,515,841
Other	1,146,791
PW1 - Major Maint Deferral	(1,178,781)
PW2 - Major Maint Deferral	(826,853)
RPA Balancing	65,059,040
Steam Sales	2,562,812
Transmission Resale	4,712,104
Gas Resale	9,531,756
ETO Management	23,855
Sch. 7 Norm Adj	(14,265,080)
Sch. 32 Norm Adj	2,794,968
Sch. 83 Norm Adj	499,489
Accumulated ARO Boardman	520,820
General Parks & Recreation	3,168
Boardman Inventory Write-Off	174,518
Grand Total	77,743,873

(m) Concept: OtherElectricRevenue

Line 21	
Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
PW2 - Major Maint Deferral	-826853.04
RPA Balancing	65059040.1
Steam Sales	2562812.2
Transmission Resale	4712104.37
Gas Resale	9531756.11
ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

(n) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $18,367,467 in revenue related to the delivery of 632,946 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregons electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utilitys remaining energy customers. For 2020, 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).

(o) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $27,601,676 in revenue related to the delivery of 1,486,266 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2020, 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).

(p) 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 ExpertsField Service ChargesMeter Tamper ChargesMeter Test ChargesMeter Verification ChargesReconnect ChargesReturned Check Charges

(q) Concept: OtherElectricRevenue

Other Electric Revenues consist of the following: Q4-2020 Boardman Decommissioning Balancing Account (2,800)Boardman Ops 217,435 Boardman Severance 2,343,630 Carty Major Maintenance Deferral (648,342)Colstrip - Major Maint Accrual/Defr 129,151 Hydro License Implementation and Compliance 816,290 Lost Revenue Recovery 272,039 MCI Metro 5,342,471 Other 673,727 PW1 - Major Maint Deferral (1,764,825)PW2 - Major Maint Deferral (968,678)RPA Balancing 63,144,577 Steam Sales 1,419,239 Transmission Resale 7,246,772 Gas Resale 441,617 ETO Management 17,567 Sch. 7 Norm Adj (2,166,598)Sch. 32 Norm Adj 4,168,945 Sch. 83 Norm Adj 5,537,665 Accumulated ARO Boardman 8,567,256 Grand Total 94,787,137

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	7,908,797	1,044,483,533	800,372	9,881	0.1321
2	15 - Outdoor Area Lighting	1,696	656,142	0		0.3869
41	TOTAL Billed Residential Sales	7,910,493	1,045,139,675	800,372	9,884	0.1321
42	TOTAL Unbilled Rev. (See Instr. 6)	67,606	11,229,000			0.1661
43	TOTAL	7,978,099	1,056,368,675	800,372	9,968	0.1324

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	12,303	2,725,882			0.2216
2	32 - Small Nonresidential	1,532,102	191,831,448	93,811	16,332	0.1252
3	38 - Large Nonresidential	27,442	3,822,853	373	73,571	0.1393
4	47 - Small Irrigation & Drainage	21,583	4,377,658	2,686	8,035	0.2028
5	49 - Large Irrigation & Drainage	69,643	10,388,955	1,390	50,103	0.1492
6	83 - Large Nonresidential	2,810,874	278,654,503	11,468	245,106	0.0991
7	85 - Large Nonresidential	1,922,160	167,389,580	1,132	1,698,021	0.0871
8	89 - Large Nonresidential	100,525	7,316,591	3	33,508,333	0.0728
9	485 - Large Nonresidential	4,045	554,354	3	1,348,333	0.1370
10	485 - Large Nonresidential DAS		11,627,690	223	0	
11	489 - Large Nonresidential DAS		35,619	[(a)] [(b)] [(c)] [(d)] 0		
12	515 - Outdoor Area Lighting DAS		5,922	0		
13	532 - Small Nonresidential DAS		324,052	140		
14	538 - Large Nonresidential Opt. DAS		3,011	2		
15	583 - Large Nonresidential DAS		1,875,667	92		
16	585 - Large Nonresidential DAS		3,738,527	46		
41	TOTAL Billed Small or Commercial	6,500,677	684,672,312	111,369	58,371	0.1053
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	54,603	6,645,000			0.1217
43	TOTAL Small or Commercial	6,555,280	[(e)] 691,317,312	111,369	58,861	0.1055

FOOTNOTE DATA

(a) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercialBilled

The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.

(b) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercialBilled

The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.

(c) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercialBilled

(d) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercialBilled

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $17,612,608 in revenue related to the delivery of 589,500 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregons electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utilitys remaining energy customers. For 2021, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	85 - Large Nonresidential	579,396	46,443,333	169	3,428,379	0.0802
2	89 - Large Nonresidential	542,007	38,299,180	17	31,882,765	0.0707
3	90 - Large Nonresidential	2,532,498	160,855,505	5	506,499,600	0.0635
4	485 - Large Nonresidential	648	59,775	[(a)] [(b)] [(c)] [(d)] 0		0.0922
5	489 - Large Nonresidential	42,808	2,089,031	[(e)] [(f)] [(g)] [(h)] 0		0.0488
6	689 - Large Nonresidential	163	55,628	[(i)] [(j)] [(k)] [(l)] 0		0.3413
7	485 - Large Nonresidential DAS		7,131,675	55	0	
8	489 - Large Nonresidential DAS		21,408,232	18	0	
9	585 - Large Nonresidential DAS		527,065	3	0	
10	689 - Large Nonresidential DAS		337,622	1	0	
41	TOTAL Billed Large (or Ind.) Sales	3,697,520	277,207,046	268	13,796,716	0.0750
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	16,160	2,669,000			0.1652
43	TOTAL Large (or Ind.)	3,713,680	[(m)] 279,876,046	268	13,857,015	0.0754

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.
(b) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.
(c) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
(d) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
(e) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.
(f) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.
(g) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
(h) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
(i) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.
(j) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
The average number of customers, which is calculated as the number of bills rendered during the year divided by the number of billing periods (12, monthly), was fewer than 0.5 and thus is rounded down to 0.
(k) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
(l) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled
(m) Concept: LargeOrIndustrialSalesElectricOperatingRevenue
Includes $29,706,344 in revenue related to the delivery of 1,646,921 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2021, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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						
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3						
4						
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6						
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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)
37						
38						
39						
40						
41	TOTAL Billed Commercial and Industrial Sales			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	0	0			

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	19,424	6,170,164	183	106,287	0.3177
2	92 - Traffic Signals	2,736	243,683	16	171,012	0.0891
3	95 - Street & Hwy Lighting	26,835	5,509,044	1	26,834,901	0.2053
41	TOTAL Billed Public Street and Highway Lighting	48,995	11,922,891	200	244,975	0.2433
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	48,995	11,922,891	200	244,975	0.2433

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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						
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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)
37						
38						
39						
40						
41	TOTAL Billed Other Sales to Public Authorities			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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						
2						
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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)
37						
38						
39						
40						
41	TOTAL Billed Sales To Railroads and Railways			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						

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)
37						
38						
39						
40						
41	TOTAL Billed Interdepartmental Sales			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						

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)
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds			0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		17,402,956			

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	18,157,685	2,018,941,924	912,209	19,905	0.1112
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	138,369	20,543,000			0.1485
43	TOTAL - All Accounts	18,296,054	2,039,484,924	912,209	20,057	0.1115

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
1	Avangrid Renewables (was Iberdrola)	SF	EEI			
2	Atlas Energy, LLC	SF	EEI			
3	Arizona Public Service Co.	SF	EEI			
4	Avista Corp.	SF	WSPP-1			
5	BP Energy Company	SF	PGE-11			
6	Black Hills Power	SF	WSPP-1			
7	Bonneville Power Administration	SF	WSPP-1			
8	British Columbia Hydro & Power Authoirty	SF	WSPP-1			
9	Brookfield Energy Marketing LP	SF	WSPP-1			
10	California Independent System Operator	SF	CAISO			
11	Calpine Energy Services, L.P.	SF	EEI			
12	Calpine Energy Services	OS	WSPP-1			
13	Chelan County, PUD No. 1, Washington	SF	WSPP-1			
14	Citigroup Energy Inc.	SF	WSPP-1			
15	City of Burbank	SF	WSPP-1			
16	City of Glendale	SF	WSPP-1			
17	City of Redding	SF	WSPP-1			
18	City of Roseville	SF	WSPP-1			
19	Clatskanie Peoples Utility District	SF	WSPP-1			
20	ConocoPhillips Company	SF	WSPP-1			
21	Direct Energy Business Marketing	SF	WSPP-1			
22	Douglas County, PUD No. 1, Washington	(b) LF	WSPP-1			
23	DTE Energy Trading LLC	SF	WSPP-1			
24	EAST BAY COMMUNITY ENERGY AUTHORITY	OS	WSPP-1			
25	EDF Trading North America, LLC	SF	WSPP-1			
26	Element Markets	OS	EEI			
27	Energy America	OS	WSPP-1			
28	Energy Keepers, Inc.	SF	WSPP-1			
29	ENMAX Energy Marketing Inc.	SF	EEI			
30	Eugene Water & Electric Board	SF	WSPP-1			
31	Exelon Generation Company, LLC	SF	EEI			
32	Gridforce Energy Management	SF	NWPP			
33	Idaho Power Company	SF	WSPP-1			
34	Load Balance Energy	OS	OATT			

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)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
35	Los Angeles Dept. Water Power	SF	WSPP-1			
36	Macquarie Energy LLC	SF	WSPP-1			
37	Mercuria Energy America, LLC	SF	WSPP-1			
38	Morgan Stanley Capital Group, Inc.	SF	PGE-11			
39	Marin Clean Energy	OS	WSPP-1			
40	NaturEner Power Watch, LLC	SF	NWPP			
41	NextEra Energy Power Marketing, LLC	SF	WSPP-1			
42	Northern California Power Agency	SF	WSPP-1			
43	NorthWestern Corporation	SF	WSPP-1			
44	PacifiCorp	SF	EEI			
45	PacifiCorp	(c) LU	PGE-11			
46	Powerex Corp.	SF	EEI			
47	Pend Orielle County PUD	SF	WSPP-1			
48	PENINSULA CLEAN ENERGY AUTHORITY	OS	WSPP-1			
49	Pionner Community Energy	OS	WSPP-1			
50	Puget Sound Energy	SF	WSPP-1			
51	Rainbow Energy Marketing Company	SF	WSPP-1			
52	San Diego Community Power	OS	WSPP-1			
53	San Diego Gas & Electric	OS	WSPP-1			
54	San Jose Clean Energy	OS	WSPP-1			
55	Sacramento Municipal Utility District	SF	WSPP-1			
56	Sacramento Municipal Utility District	OS	WSPP-1			
57	Seattle City Light	SF	WSPP-1			
58	Shell Energy North America (US), L.P.	SF	PGE-11			
59	Snohomish County, PUD No.1, Washington	SF	WSPP-1			
60	Southern California Edison	SF	EEI			
61	Tacoma Power	SF	WSPP-1			
62	Tenaska Power Services Co.	SF	WSPP-1			
63	The Energy Authority, Inc.	SF	WSPP-1			
64	The Energy Authority, Inc.	OS	WSPP-1			
65	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI			
66	TransCanada Energy Sales Ltd.	SF	WSPP-1			
67	Tucson Electric Power Company	SF	WSPP-1			
68	Turlock Irrigation District	SF	WSPP-1			
69	Vitol Inc.	SF	WSPP-1			
70	Umatilla Electric Cooperative	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)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)
71	Warm Springs Power Enterprises	OS	WSPP-1			
72	Western Area Power Authority	SF	NWPP			
73	Direct Access deferral 2020					
74	Direct Access amortization-2020					
75	Deferral of certain NVPC benefits					
76	[(a)] Portland General Electric Total	SF	OA96137	810.202		
15	Subtotal - RQ					
16	Subtotal-Non-RQ					
17	Total					

SALES FOR RESALE (Account 447)

Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	223,005	0	15,050,985	0	15,050,985
2	88,790	0	6,227,548	0	6,227,548
3	36	0	714	0	714
4	40,285	0	1,610,958	0	1,610,958
5	53,736	0	3,232,110	0	3,232,110
6	7,342	0	2,638,455	0	2,638,455
7	293,515	0	13,527,215	0	13,527,215
8	292	0	23,254	0	23,254
9	4,930	0	195,468	0	195,468
10	2,620,084	0	108,378,939	0	108,378,939
11	29,745	0	1,693,587	0	1,693,587
12	0	0	0	(k) 1,675,950	1,675,950
13	8,405	0	238,822	0	238,822
14	46,397	0	1,521,787	0	1,521,787
15	630	0	33,560	0	33,560
16	20,780	0	935,100	0	935,100
17	23,620	0	896,038	0	896,038
18	400	0	184,000	0	184,000
19	4,141	0	164,486	0	164,486
20	32,341	0	1,436,023	0	1,436,023
21	64,851	0	3,726,611	0	3,726,611
22	1,036,194	0	6,218,047	0	6,218,047
23	7,600	0	333,788	0	333,788
24	0	0	0	(l) (m) (n) (o) (p) (q) (r) (s) (t) (u) (v) (w) (x) (y) (z) (aa) (ab) (ac) (ad) (ae) (af) (ag) (ah) (ai) (aj) 6,030,000	6,030,000
25	36,946	0	2,998,493	0	2,998,493
26	0	0	0	(ak) (al) (am) (an) (ao) 298,713	298,713
27	0	0	0	(ap) (aq) (ar) (as) (at) 362,500	362,500
28	49,720	0	1,510,606	0	1,510,606
29	50	0	1,450	0	1,450
30	18,481	0	846,262	0	846,262
31	29,466	0	1,447,525	0	1,447,525
32	268	0	10,779	0	10,779
33	19,633	0	1,815,249	0	1,815,249
34	(d) (e) (f) (g) (h) (i) (j) 82,468	0	0	0	0
35	35	0	65,723	0	65,723
36	139,680	0	7,389,665	0	7,389,665
37	800	0	40,800	0	40,800
38	104,317	0	4,804,048	0	4,804,048
39	0	0	0	(au) (av) (aw) (ax) (ay) 1,400,000	1,400,000

SALES FOR RESALE (Account 447)

Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
40	193	0	5,799	0	5,799
41	135	0	11,039	0	11,039
42	9,768	0	70,400	0	70,400
43	101,865	0	5,605,203	0	5,605,203
44	126,555	0	6,575,244	0	6,575,244
45	16,995	0	94,080	0	94,080
46	84,465	0	2,557,547	0	2,557,547
47	0	0	25,186	0	25,186
48	0	0	0	(az) (ba) (bb) (bc) (bd) 1,335,000	1,335,000
49	0	0	0	(be) (bf) (bg) (bh) (bi) 350,000	350,000
50	64,331	0	2,592,391	0	2,592,391
51	1,720	0	249,294	0	249,294
52	0	0	0	(bj) (bk) (bl) (bm) (bn) 326,092	326,092
53	0	0	0	(bo) (bp) (bq) (br) (bs) 793,396	793,396
54	0	0	0	(bt) (bu) (bv) (bw) (bx) 235,555	235,555
55	48,142	0	6,698,407	0	6,698,407
56	0	0	0	(by) (bz) (ca) (cb) (cc) 971,082	971,082
57	28,109	0	1,777,952	0	1,777,952
58	91,382	0	5,451,604	0	5,451,604
59	10,894	0	538,570	0	538,570
60	240,787	0	21,967,480	0	21,967,480
61	3,085	0	78,544	0	78,544
62	87,626	0	2,468,746	0	2,468,746
63	113,563	0	5,406,813	0	5,406,813
64	0	0	0	(cd) (ce) (cf) (cg) (ch) 1,634,820	1,634,820
65	203,869	0	11,549,953	0	11,549,953
66	47,241	0	1,897,088	0	1,897,088
67	753	0	222,750	0	222,750
68	65	0	2,501	0	2,501
69	2,600	0	77,650	0	77,650
70	110,450	0	5,323,690	0	5,323,690
71	0	0		(ci) 4,540,050	4,540,050
72	400	0	9,100	0	9,100
73	0	0	0	(cj) 261,952	261,952
74	0	0	0	(ck) 286,775	286,775
75	0	0	0	(cl) (3,709,405)	(3,709,405)
76	0	35,013	0	0	35,013
15					0
16	6,483,976	35,013	270,455,126	16,792,480	287,282,619

SALES FOR RESALE (Account 447)					
Line No.	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
17	6,483,976	35,013	270,455,126	16,792,480	(cm)287,282,619

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

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

(b) Concept: StatisticalClassificationCode

Represents the Douglas County contract expires on 12/31/2025.

(c) Concept: StatisticalClassificationCode

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

(d) Concept: MegawattHoursSoldSalesForResale

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

(e) Concept: MegawattHoursSoldSalesForResale

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

(f) Concept: MegawattHoursSoldSalesForResale

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

(g) Concept: MegawattHoursSoldSalesForResale

Represents the value of energy received from the PGE control area toElectricity Service Suppliers in excess of the ESS's actual load withinthe PGE control area.

(h) Concept: MegawattHoursSoldSalesForResale

Represents the value of energy received from the PGE control area toElectricity Service Suppliers in excess of the ESS's actual load withinthe PGE control area.

(i) Concept: MegawattHoursSoldSalesForResale

Represents the value of energy received from the PGE control area toElectricity Service Suppliers in excess of the ESS's actual load withinthe PGE control area.

(j) Concept: MegawattHoursSoldSalesForResale

Represents the value of energy received from the PGE control area toElectricity Service Suppliers in excess of the ESS's actual load withinthe PGE control area.

(k) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty

(l) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(m) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(n) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(o) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(p) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(q) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(r) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(s) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(t) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(u) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(v) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(w) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.

(x) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to this counterparty.
(y) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(z) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(aa) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ab) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ac) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ad) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ae) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(af) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ag) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ah) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ai) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(aj) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ak) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(al) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(am) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(an) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ao) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ap) Concept: OtherChargesRevenueSalesForResale
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(aq) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ar) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(as) Concept: OtherChargesRevenueSalesForResale
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(at) Concept: OtherChargesRevenueSalesForResale
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(au) Concept: OtherChargesRevenueSalesForResale
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(av) Concept: OtherChargesRevenueSalesForResale
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(aw) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ax) Concept: OtherChargesRevenueSalesForResale
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(ay) Concept: OtherChargesRevenueSalesForResale
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(az) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ba) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bb) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bc) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bd) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(be) Concept: OtherChargesRevenueSalesForResale
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(bf) Concept: OtherChargesRevenueSalesForResale
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(bg) Concept: OtherChargesRevenueSalesForResale
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(bh) Concept: OtherChargesRevenueSalesForResale
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(bi) Concept: OtherChargesRevenueSalesForResale
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(bj) Concept: OtherChargesRevenueSalesForResale
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(bk) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bl) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bm) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bn) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bo) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bp) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bq) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(br) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bs) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bt) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bu) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bv) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bw) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bx) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(by) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(bz) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.

(ca) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(cb) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(cc) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(cd) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ce) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(cf) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(cg) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ch) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits to this counterparty.
(ci) Concept: OtherChargesRevenueSalesForResale
Represents the sell side of a financial transaction with the counterparty.
(cj) Concept: OtherChargesRevenueSalesForResale
Defer costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.
(ck) Concept: OtherChargesRevenueSalesForResale
Amortization of deferred costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.
(cl) Concept: OtherChargesRevenueSalesForResale
Deferral of certain NVPC benefits
(cm) Concept: SalesForResale

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	(185,773)	2,351,045
5	(501) Fuel	37,330,033	70,676,152
6	(502) Steam Expenses	2,609,507	15,834,155
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	2,845,705	7,903,659
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	42,599,472	96,765,011
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	815,410	964,898
16	(511) Maintenance of Structures	824,949	993,652
17	(512) Maintenance of Boiler Plant	7,590,866	8,181,488
18	(513) Maintenance of Electric Plant	1,885,553	5,096,511
19	(514) Maintenance of Miscellaneous Steam Plant	551,253	836,609
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,668,031	16,073,158
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	54,267,503	112,838,169
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	698,710	787,010
45	(536) Water for Power	610,988	608,858
46	(537) Hydraulic Expenses	7,702,703	7,149,131
47	(538) Electric Expenses	1,945,868	1,701,819
48	(539) Miscellaneous Hydraulic Power Generation Expenses	4,188,435	3,375,138
49	(540) Rents	1,224,641	809,334
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	16,371,345	14,431,290
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	631,958	994,464
54	(542) Maintenance of Structures		4,894
55	(543) Maintenance of Reservoirs, Dams, and Waterways	404,148	362,086
56	(544) Maintenance of Electric Plant	1,414,401	1,355,885
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,757,699	1,580,035
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,208,206	4,297,364
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	20,579,551	18,728,654
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,393,790	3,369,465
63	(547) Fuel	199,194,004	170,765,398
64	(548) Generation Expenses	10,640,124	8,506,242
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	12,481,880	13,416,046
66	(550) Rents	970,116	944,505
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	226,679,914	197,001,656
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,018,896	1,686,939
70	(552) Maintenance of Structures	281,194	292,574
71	(553) Maintenance of Generating and Electric Plant	36,150,777	30,378,456
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,287,533	1,037,697

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	39,738,400	33,395,666
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	266,418,314	230,397,322
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	530,010,343	418,799,466
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	219,862	238,013
78	(557) Other Expenses	26,434,259	21,170,453
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	556,664,464	440,207,932
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	897,929,832	802,172,077
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,946,251	7,440,319
85	(561.1) Load Dispatch-Reliability	17,016	16,150
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,189,054	1,053,301
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,605,810	1,400,410
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	67,990	195,430
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	381,060	290,541
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	566,311	313,338
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	102,142,822	81,280,168
97	(566) Miscellaneous Transmission Expenses	(4,851,312)	2,975,438
98	(567) Rents	3,153,180	2,908,566
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	108,218,182	97,873,661
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	14,997	10,247
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	815,973	748,322
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,468,539	1,565,923
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	1,390,275	1,326,886

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	**Account (a)**	**Amount for Current Year (b)**	**Amount for Previous Year (c) (c)**
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		778
111	TOTAL Maintenance (Total of Lines 101 thru 110)	3,689,784	3,652,156
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	111,907,966	101,525,817
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	22,809,847	17,715,664
135	(581) Load Dispatching	3,293,027	2,687,850
136	(582) Station Expenses	2,135,285	812,703
137	(583) Overhead Line Expenses	5,903,535	2,927,260
138	(584) Underground Line Expenses	3,817,795	4,218,614
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	472,951	235,512
140	(586) Meter Expenses	2,414,677	2,292,043
141	(587) Customer Installations Expenses	1,869,800	3,021,147
142	(588) Miscellaneous Expenses	11,686,728	10,605,286
143	(589) Rents	2,142,897	1,687,489
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	56,546,542	46,203,568
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	286,705	37,138

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
147	(591) Maintenance of Structures	235,555	172,665
148	(592) Maintenance of Station Equipment	4,837,440	4,835,898
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	79,678,452	55,034,683
150	(594) Maintenance of Underground Lines	9,724,536	8,069,382
151	(595) Maintenance of Line Transformers	926,877	1,881,127
152	(596) Maintenance of Street Lighting and Signal Systems	819,978	947,941
153	(597) Maintenance of Meters	27,303	5,790
154	(598) Maintenance of Miscellaneous Distribution Plant	6,765,544	6,817,818
155	TOTAL Maintenance (Total of Lines 146 thru 154)	103,302,390	77,802,442
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	159,848,932	124,006,010
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	491,460	352,224
161	(903) Customer Records and Collection Expenses	58,810,443	50,657,698
162	(904) Uncollectible Accounts	5,977,000	7,069,010
163	(905) Miscellaneous Customer Accounts Expenses	5,644,153	5,547,635
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	70,923,056	63,626,567
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	16,807,204	14,614,122
169	(909) Informational and Instructional Expenses	1,686,047	1,821,001
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	18,493,251	16,435,123
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	100,387,787	80,315,704
182	(921) Office Supplies and Expenses	17,723,785	17,790,843
183	(Less) (922) Administrative Expenses Transferred-Credit	13,283,259	12,633,527

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
184	(923) Outside Services Employed	23,884,579	13,849,356
185	(924) Property Insurance	9,181,298	6,911,324
186	(925) Injuries and Damages	6,121,365	4,107,996
187	(926) Employee Pensions and Benefits	62,571,896	57,727,595
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,828,394	10,485,584
190	(929) (Less) Duplicate Charges-Cr.	2,637,225	2,325,928
191	(930.1) General Advertising Expenses	1,763,214	1,045,923
192	(930.2) Miscellaneous General Expenses	15,729,906	20,720,146
193	(931) Rents	5,542,724	3,914,762
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	238,814,464	201,909,778
195	Maintenance		
196	(935) Maintenance of General Plant	3,300,424	2,785,844
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	242,114,888	204,695,622
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,501,217,925	1,312,461,216

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
1	Arizona Public	SF	EEI				29,427
2	Airport Solar, LLC	LU	201				118,736
3	Alkali Solar	LU	201				27,960
4	Avangrid Renewables (was Iberdrola)	SF	PGE-11				518,616
5	Avangrid Renewables (was berdrola Renewables)	LU	PGE-11				222,105
6	Avangrid Renewables (was Iberdrola)	LU	PGE-11				0
7	Avista Corp. - AVWP (was WWP)	SF	WSPP-1				51,138
8	Atlas Enery	SF	EEI				1,456
9	BP Energy Company	SF	PGE-11				26,800
10	Bighorn Solar	LU	201				0
11	Ballston Solar	LU	201				2,275
12	Bellevue Solar	LU	Bellevue				0
13	Black Hills Power	SF	WSPP-1				460
14	Bonneville Power Administration	SF	WSPP-1				759,147
15	Bonneville Power Administration	(m) LF	WSPP-1				344,071
16	Bonneville Power Administration	SF	WSPP-1				0
17	Boring Solar	LU	201				2,103
18	Brookfield Energy Marketing	SF	WSPP-1				23,617
19	CP Energy Marketing (US)	SF	WSPP-1				3,254
20	California Independent System Operator	SF	CAISO				858,732
21	Calpine Energy Services	SF	PGE-11				669,797
22	Case Creek Solar	LU	201				0
23	Brush Creek Solar, LLC	LU	201				0
24	Bristol Solar LLC	LU	201				0
25	Butler Slar	LU	201				0
26	Chelan County, PUD No. 1, Washington	SF	WSPP-1				91,221
27	Citigroup Energy	SF	WSPP-1				33,000
28	Burbank, City of	SF	WSPP-1				550
29	Clatskanie County PUD	SF	WSPP-1				3,816
30	Columbia Basin Electric Cooperative Inc.	LU	OATT				0
31	ConocoPhillips	SF	WSPP-1				209,589
32	Covanta Marion	LU	QF83-118				64,882

PURCHASED POWER (Account 555)							
					Actual Demand (MW)	Actual Demand (MW)	
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
33	Day Hill Solar	LU	201				0
34	Douglas County, PUD No. 1, Washington	LU	WSPP-1				2,219,594
35	Douglas County, PUD No. 1, Washington	LU	WSPP-1				0
36	DTE Energy Trading, Inc.	SF	WSPP-1				2,400
37	EDF Trading North America, LLC	SF	WSPP-1				2,601
38	Enmax	SF	EEI				500
39	Energy Keepers, Inc. - ENKP	SF	WSPP-1				7,316
40	ESI Vansycle Partners, LP	LU	WSPP-1				67,947
41	Eugene Water & Electric Board	LU	WSPP-1				0
42	Eugene Water & Electric Board	SF	WSPP-1				9,698
43	Evergreen Biomass	LU	201				55,583
44	Exelon Generation Co.	SF	WSPP-1				76,975
45	Falls Creek Hydro	LU	201				14,304
46	Fort Rock Solar 1	LU	201				28,592
47	Fort Rock Solar 4	LU	201				27,589
48	Gridforce Energy Management - GRID	SF	NWPP				7
49	Idaho Power Company	SF	WSPP-1				14,266
50	Labish Solar	LU	201				2,235
51	Los Angeles Depart Water Power	SF	WSPP-1				62,229
52	Macquarie Cook Power	SF	WSPP-1				80,175
53	Milford Solar	LU	201				0
54	Minke Solar	LU	201				0
55	Morgan Stanley Capital Group	SF	PGE-11				71,150
56	Montague Solar	SF	WSPP-1				0
57	NextEra Energy Power Marketing, LLC	SF	WSPP-1				4,720
58	NextEra Energy Power Marketing, LLC	(n) LF	WSPP-1				317,558
59	NaturEner Power Watch, LLC	SF	WSPP-1				1
60	NorthWestern Corporation	SF	WSPP-1				50,552
61	Northwestern Energy	SF	WSPP-1				0
62	Norwest Energy 14	LU	201				2,993
63	Obsidian Lakeview	LU	201				26,442
64	OE Solar 3, LLC	LU	201				28,932
65	O'Neil Solar	LU	201				2,147
66	Outback Solar	LU	Outback				10,505

PURCHASED POWER (Account 555)							
					Actual Demand (MW)	Actual Demand (MW)	
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
67	Pacific Northwest Generating Company	SF	WSPP-1				64,515
68	PacifiCorp	SF	PGE-11				55,769
69	Palmer Creek Solar	LU	201				0
70	PaTu Wind	LU	WSPP-1				30,170
71	Duus Solar (Alchemy)	LU	201				20,032
72	Portland, City of	LU	#2821				69,599
73	Powerex	SF	PGE-11				170,251
74	Public Service Co of Colorado	SF	WSPP-1				30,835
75	Grant County, PUD No. 2, Washington	LU	Wanapum				377,390
76	Grant County, PUD No. 2, Washington	LU	Priest Rapids				377,390
77	Grant County, PUD No. 2, Washington	SF	WSPP-1				139,223
78	Greenpark Solar, LLC	LU	201				0
79	City of Redding	SF	WSPP-1				1,930
80	Puget Sound Energy	SF	WSPP-1				279,998
81	Rafael Solar	LU	201				2,172
82	Riley Solar	LU	201				25,949
83	Rock Garden Solar	LU	201				28,003
84	Seattle City Light	SF	WSPP-1				90,731
85	Shell Energy	SF	WSPP-1				163,964
86	Sheep Solar	LU	201				3,989
87	Silverton Solar	LU	201				3,887
88	Snohomish County, PUD No. 1, Washington	SF	WSPP-1				106,687
89	SP Solar 1, LLC	LU	201				3,028
90	SP Solar 5, LLC	LU	201				3,028
91	SP Solar 6, LLC	LU	201				3,021
92	SP Solar 7, LLC	LU	201				3,028
93	SP Solar 8, LLC	LU	201				3,028
94	SSD Clackamas 1	LU	201				0
95	SSD Clackamas 4	LU	201				0
96	SSD Clackamas 7	LU	201				0
97	SSD Marion 1	LU	201				0
98	SSD Marion 3	LU	201				0
99	SSD Marion 5	LU	201				0
100	SSD Marion 6	LU	201				0
101	Steel Bridge	LU	201				3,614

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
102	Starvation Solar 1 LLC	LU	201				25,558
103	St Louis Solar	LU	201				0
104	Suluss Solar 35	LU	201				0
105	Suluss Solar 33	LU	201				0
106	Suluss Solar 22	LU	201				0
107	Suluss Solar 25	LU	201				0
108	Suluss Solar 28	LU	201				0
109	Suluss Solar 29	LU	201				0
110	Suluss Solar 17	LU	201				0
111	Suntex Solar	LU	201				27,510
112	West Hines Solar	LU	201				25,867
113	Tacoma, City of	SF	WSPP-1				42,221
114	Tenaska Power Services	SF	WSPP-1				9,927
115	The Energy Authority	SF	WSPP-1				102,271
116	Thomas Creek Solar	LU	201				3,732
117	Tickle Creek	LU	201				2,899
118	TransAlta Energy Marketing	SF	PGE-11				219,431
119	TransCanada Energy Marketing	SF	WSPP-1				50
120	Tucson Electric Power Company	SF	WSPP-1				46
121	Turlock Irrigation District	SF	WSPP-1				86,125
122	Vitol Inc.	SF	WSPP-1				13,800
123	Volcano Solar	LU	201				708
124	VON FAMILY LTD PARTNERSHIP	LU	201				250
125	WAPA - Upper Great Plains Region	SF	NWPP				1
126	UMATILLA ELECTRIC COOPERATIVE	SF	EEI				0
127	Warm Springs Power Enterprises	LU	WSPP-1				417,850
128	Warm Springs Power Enterprises	LU	WSPP-1				0
129	Wheatridge Wind II, LLC	LU	WSPP-1				669,172
130	Kale Patch Solar	LU	201				3,725
131	Drift Creek	LU	201				0
132	Yamhill Solar	LU	Yamhill				0
133	[(a)] [(b)] [(c)] [(d)] [(e)] [(f)] [(g)] [(h)] [(i)] [(j)] [(k)] [(l)] Load Balance Energy	OS	OATT				72,164
134	Country Village Estates	OS	[(o)] 201				0
135	Domaine Drouhin	OS	[(p)] 201				74

PURCHASED POWER (Account 555)							
					Actual Demand (MW)	Actual Demand (MW)	
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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
136	Lake Oswego Corporation	OS	(q) 201				61
137	Starbuck Properties	OS	(r) 201				35
138	Solar Payment Option	OS	(s) 215-217				18,406
139	Tualatin Valley Water Dist	OS	(t) 201				397
140	Green Power						0
141	NVPC MONET QF Deferrals						0
142	Margin on Electric Financials						0
143	Pelton Round Butte Financial Lease 33.33%						0
144	2021 PCAM Deferrals						0
145	REC Retirement Expense						0
146	Carbon Allowance Expense						0
15	TOTAL						11,053,274

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)
1	0	0	0	0	2,443,686	0	2,443,686
2	0	0	0	0	8,211,111	0	8,211,111
3	0	0	0	0	2,788,040	0	2,788,040
4	0	0	0	0	34,378,203	0	34,378,203
5	0	0	0	0	13,859,868	0	13,859,868
6	0	0	0	3,120,000	0	0	3,120,000
7	0	0	0	0	2,144,125	0	2,144,125
8	0	0	0	0	418,344	0	418,344
9	0	0	0	0	663,814	0	663,814
10	0	0	0	0	144,044	0	144,044
11	0	0	0	0	356,835	0	356,835
12	0	0	0	0	201,052	0	201,052
13	0	0	0	0	80,500	0	80,500
14	0	0	0	0	29,839,227	0	29,839,227
15	0	0	0	0	21,336,967	0	21,336,967
16	0	0	0	9,024,000	0	0	9,024,000
17	0	0	0	0	357,746	0	357,746
18	0	0	0	0	1,268,523	0	1,268,523
19	0	0	0	0	525,710	0	525,710
20	0	0	0	0	18,048,020	0	18,048,020
21	0	0	0	0	36,877,547	0	36,877,547
22	0	0	0	0	400,291	0	400,291
23	0	0	0	0	119,543	0	119,543
24	0	0	0	0	123,292	0	123,292
25	0	0	0	0	793,666	0	793,666
26	0	0	0	0	4,781,833	0	4,781,833
27	0	0	0	0	2,137,410	0	2,137,410
28	0	0	0	0	30,700	0	30,700
29	0	0	0	0	120,128	0	120,128
30	0	0	0	0	83,768	0	83,768
31	0	0	0	0	8,909,281	0	8,909,281
32	0	0	0	0	2,492,051	0	2,492,051
33	0	0	0	0	335,253	0	335,253
34	0	0	0	0	67,599,887	0	67,599,887
35	0	0	0	6,127,605	0	0	6,127,605
36	0	0	0	0	59,700	0	59,700
37	0	0	0	0	1,113,162	0	1,113,162

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)
38	0	0	0	0	85,000	0	85,000
39	0	0	0	0	396,216	0	396,216
40	0	0	0	0	4,633,326	0	4,633,326
41	0	0	0	77,000	0	0	77,000
42	0	0	0	0	345,167	0	345,167
43	0	0	0	0	5,257,245	0	5,257,245
44	0	0	0	0	3,313,971	0	3,313,971
45	0	0	0	0	1,214,291	0	1,214,291
46	0	0	0	0	2,551,011	0	2,551,011
47	0	0	0	0	2,484,323	0	2,484,323
48	0	0	0	0	673	0	673
49	0	0	0	0	589,517	0	589,517
50	0	0	0	0	312,797	0	312,797
51	0	0	0	0	7,877,372	0	7,877,372
52	0	0	0	0	6,079,584	0	6,079,584
53	0	0	0	0	133,459	0	133,459
54	0	0	0	0	114,218	0	114,218
55	0	0	0	0	6,386,686	0	6,386,686
56	0	0	0	0	[(e)](600,000)	0	(600,000)
57	0	0	0	0	272,585	0	272,585
58	0	0	0	0	24,805,606	0	24,805,606
59	0	0	0	0	66	0	66
60	0	0	0	0	1,765,017	0	1,765,017
61	0	0	0	0	680,550	0	680,550
62	0	0	0	0	355,958	0	355,958
63	0	0	0	0	2,480,868	0	2,480,868
64	0	0	0	0	2,546,499	0	2,546,499
65	0	0	0	0	373,646	0	373,646
66	0	0	0	0	1,092,108	0	1,092,108
67	0	0	0	0	3,874,814	0	3,874,814
68	0	0	0	0	2,801,904	0	2,801,904
69	0	0	0	0	430,979	0	430,979
70	0	0	0	0	2,571,926	0	2,571,926
71	0	0	0	0	3,261,287	0	3,261,287
72	0	0	0	0	2,250,547	0	2,250,547
73	0	0	0	0	14,275,043	0	14,275,043
74	0	0	0	0	964,338	0	964,338

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)
75	0	0	0	0	12,825,407	0	12,825,407
76	0	0	0	0	12,825,407	0	12,825,407
77	0	0	0	0	2,821,293	0	2,821,293
78	0	0	0	0	52,799	0	52,799
79	0	0	0	0	41,500	0	41,500
80	0	0	0	0	13,708,139	0	13,708,139
81	0	0	0	0	402,900	0	402,900
82	0	0	0	0	2,320,919	0	2,320,919
83	0	0	0	0	2,478,612	0	2,478,612
84	0	0	0	0	3,411,333	0	3,411,333
85	0	0	0	0	9,417,206	0	9,417,206
86	0	0	0	0	365,897	0	365,897
87	0	0	0	0	342,543	0	342,543
88	0	0	0	0	3,777,713	0	3,777,713
89	0	0	0	0	364,348	0	364,348
90	0	0	0	0	381,323	0	381,323
91	0	0	0	0	361,150	0	361,150
92	0	0	0	0	353,121	0	353,121
93	0	0	0	0	375,977	0	375,977
94	0	0	0	0	90,381	0	90,381
95	0	0	0	0	239,627	0	239,627
96	0	0	0	0	179,174	0	179,174
97	0	0	0	0	116,775	0	116,775
98	0	0	0	0	212,450	0	212,450
99	0	0	0	0	243,532	0	243,532
100	0	0	0	0	285,135	0	285,135
101	0	0	0	0	296,446	0	296,446
102	0	0	0	0	2,285,385	0	2,285,385
103	0	0	0	0	396,639	0	396,639
104	0	0	0	0	132,050	0	132,050
105	0	0	0	0	133,642	0	133,642
106	0	0	0	0	108,598	0	108,598
107	0	0	0	0	97,961	0	97,961
108	0	0	0	0	147,017	0	147,017
109	0	0	0	0	104,591	0	104,591
110	0	0	0	0	114,053	0	114,053
111	0	0	0	0	2,471,480	0	2,471,480

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)
112	0	0	0	0	2,304,332	0	2,304,332
113	0	0	0	0	4,598,701	0	4,598,701
114	0	0	0	0	103,415	0	103,415
115	0	0	0	0	4,056,333	0	4,056,333
116	0	0	0	0	320,532	0	320,532
117	0	0	0	0	220,547	0	220,547
118	0	0	0	0	13,088,405	0	13,088,405
119	0	0	0	0	2,650	0	2,650
120	0	0	0	0	2,025	0	2,025
121	0	0	0	0	1,729,941	0	1,729,941
122	0	0	0	0	912,556	0	912,556
123	0	0	0	0	100,864	0	100,864
124	0	0	0	0	12,785	0	12,785
125	0	0	0	0	2,362,385	0	2,362,385
126	0	0	0	0	[v] (575,000)	0	(575,000)
127	0	0	0	0	23,916,017	0	23,916,017
128	0	0	0	3,000,025	0	0	3,000,025
129	0	0	0	0	384,679	0	384,679
130	0	0	0	0	339,089	0	339,089
131	0	0	0	0	1,090,525	0	1,090,525
132	0	0	0	0	125,614	0	125,614
133	0	0	0	0	0	0	0
134	0	0	0	0	7	0	7
135	0	0	0	0	22,899	0	22,899
136	0	0	0	0	2,917	0	2,917
137	0	0	0	0	3,162	0	3,162
138	0	0	0	0	431,982	0	431,982
139	0	0	0	0	26,532	0	26,532
140	0	0	0	0	0	[w] 17,184,713	17,184,713
141	0	0	0	0	0	[x] 373,080	373,080
142	0	0	0	0	0	[y] 25,848,591	25,848,591
143	0	0	0	0	0	[z] 666,667	666,667
144	0	0	0	0	0	[aa] (28,734,541)	(28,734,541)
145	0	0	0	0	0	[ab] 415,871	415,871
146	0	0	0	0	0	[ac] (5,981,010)	(5,981,010)
15	0	0	0	21,348,630	498,888,341	9,773,371	530,010,342

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(m) Concept: StatisticalClassificationCode

The BPA contract expires on 12/31/2025

(n) Concept: StatisticalClassificationCode

NextEra contract expires on 12/03/2050

(o) Concept: RateScheduleTariffNumber

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

(p) Concept: RateScheduleTariffNumber

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

(q) Concept: RateScheduleTariffNumber

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

(r) Concept: RateScheduleTariffNumber

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

(s) Concept: RateScheduleTariffNumber

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

(t) Concept: RateScheduleTariffNumber

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

(u) Concept: EnergyChargesOfPurchasedPower

Represents damages received from counterparty to compensate PGE for lost generation as the result of the supplying facility's COD delay.

(v) Concept: EnergyChargesOfPurchasedPower

Represents damages received from counterparty to compensate PGE for lost generation as the result of the supplying facility's unplanned outage.

(w) Concept: OtherChargesOfPurchasedPower

Consists of expenses related to the purchase of RECs and development of futurerenewable resources for PGEs Portfolio Options programs. Such expenses arefully offset by customer revenues.
(x) Concept: OtherChargesOfPurchasedPower
2021 NVPC MONET QF Deferrals & Cure Payments
(y) Concept: OtherChargesOfPurchasedPower
Margin on electric financial transactions.
(z) Concept: OtherChargesOfPurchasedPower
Pelton Round Butte Financial Lease amortization and interest.
(aa) Concept: OtherChargesOfPurchasedPower
2021 PCAM Deferrals
(ab) Concept: OtherChargesOfPurchasedPower
Expense of annual REC retirement to meet RPS compliance.
(ac) Concept: OtherChargesOfPurchasedPower
Expense of carbon allowances retired to comply with California'sCap-and-Trade Program.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	[b] OLF	72	BPAT.PGE	Various
2	BPA Power Business Line	Bonneville Power Administration	Other TVI Pumps Total	[c] [d] OLF	72	BPAT.PGE	Various
3	BPA Power Business Line	Bonneville Power Administration	Canby PUD Total	[e] OLF	72	BPAT.PGE	Various
4	BPA Power Business Line	Bonneville Power Administration	Columbia River PUD Total	[f] OLF	72	BPAT.PGE	Various
5	Pacificorp West	PacifiCorp	Portland General Electric	[g] [h] [i] [j] [k] [l] [m] [n] [o] [p] [q] [r] [s] [t] [u] [v] OLF	Exchange	PACW.PGE	Various
6	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
7	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO	7	BPAT.PGE	Various Subs
8	BPA Power Business Line			[w] OS	11		
9	Calpine Energy Services	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
10	Constellation New Energy	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
11	Shell Energy North America	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various
12	Avista Corp	Bonneville Power Administration	California Independent System Operator	[x] LFP	7	JohnDay	Malin500
13	Avista Corp	California Independent System Operator	Bonneville Power Administration	[y] [z] OS	8	Malin500	JohnDay
14	Avista Corp			[aa] OS	11		
15	Brookfield Renewable Trading and Marketing	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
16	Brookfield Renewable Trading and Marketing			[ab] OS	11		
17	Conoco Phillips Inc.	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE
18	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	[ac] LFP	7	JohnDay	CaptainJack
19	Shell Energy North America	Bonneville Power Administration	Portland General Electric	[ad] LFP	7	BPAT.PGE	PGE
20	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	[ae] LFP	7	JohnDay	Malin500
21	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
22	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
23	Shell Energy North America	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE
24	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	NF	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)
25	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	(af) (ag) OS	8	Malin500	JohnDay
26	Shell Energy North America			(ah) OS	11		
27	Dynasty Power Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
28	EDF Trading North America LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
29	EDF Trading North America LLC			(ai) OS	11		
30	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern California	(aj) LFP	7	JohnDay	CaptainJack
31	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	(ak) LFP	7	JohnDay	Malin500
32	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	(al) LFP	7	JohnDay	COBH
33	Constellation New Energy	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE
34	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
35	Constellation New Energy			(am) OS	11		
36	Macquarie Energy LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
37	Macquarie Energy LLC			(an) OS	11		
38	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	(ao) LFP	7	JohnDay	CaptainJack
39	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	(ap) LFP	7	JohnDay	Malin500
40	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
41	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
42	Morgan Stanley Capital Group	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
43	Morgan Stanley Capital Group	California Independent System Operator	Bonneville Power Administration	(aq) (ar) OS	8	Malin500	JohnDay
44	Morgan Stanley Capital Group			(as) OS	11		
45	Pacificorp West	Portland General Electric	Bonneville Power Administration	(at) LFP	7	RoundButte	REDMOND
46	Pacificorp West	Portland General Electric	Bonneville Power Administration	NF	8	RoundButte	REDMOND
47	Pacificorp West			(au) OS	11		
48	Avangrid Renewables, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
49	Avangrid Renewables, LLC			(av) 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)
50	Puget Sound Energy	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
51	Puget Sound Energy			[aw] OS	11		
52	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern California	[ax] LFP	7	JohnDay	CaptainJack
53	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	[ay] LFP	7	JohnDay	Malin500
54	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	[az] LFP	7	Malin500	JohnDay
55	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
56	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
57	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
58	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	[ba] [bb] OS	8	Malin500	JohnDay
59	Powerex Inc.			[bc] OS	11		
60	Rainbow Energy Marketing Corp.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
61	Rainbow Energy Marketing Corp.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
62	Rainbow Energy Marketing Corp.			[bd] OS	11		
63	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
64	Seattle City Light	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
65	Seattle City Light			[be] [bf] OS	11		
66	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	[bg] LFP	7	JohnDay	CaptainJack
67	The Energy Authority	Bonneville Power Administration	California Independent System Operator	[bh] LFP	7	JohnDay	Malin500
68	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay
69	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
70	The Energy Authority	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
71	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
72	The Energy Authority	California Independent System Operator	Bonneville Power Administration	[bi] [bj] OS	8	Malin500	JohnDay
73	The Energy Authority			[bk] OS	11		
74	Transalta Energy Marketing (US) Inc.	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)
75	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500
76	Transalta Energy Marketing (US) Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay
77	Transalta Energy Marketing (US) Inc.			(bl) OS	11		
78	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack
79	Turlock Irrigation District			(bm) (bn) OS	11		
80	Public Utility District No. 1 of Cowlitz County	Bonneville Power Administration	California Independent System Operator	(bo) LFP	7	JohnDay	COBH
81	Public Utility District No. 1 of Franklin County	Bonneville Power Administration	California Independent System Operator	(bp) LFP	7	JohnDay	COBH
82	Public Utility District No. 1 of Klickitat County	Bonneville Power Administration	California Independent System Operator	(bq) LFP	7	JohnDay	COBH
83	Public Utility District No. 1 of Lewis County	Bonneville Power Administration	California Independent System Operator	(br) LFP	7	JohnDay	COBH
84	(a) Accrual						
35	TOTAL						

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
1	0	13,885	13,775	0		[bx]97,524	97,524
2	0	8,183	8,118	0		[by]31,050	31,050
3	0	197,361	195,801	0		[bz]524,625	524,625
4	0	214,230	212,536	0		[ca]22,160	22,160
5	0	3,530	3,480	0		[cb]247,206	247,206
6	306,682	123,690	123,690	116,539	[bs](201,214)	[cc]76,126	(8,549)
7	140	69,298	69,298	48,663	[bt](170,930)	[cd]37,468	(84,799)
8	0	0	0	0	45,416	0	45,416
9	2,818,907	1,606,778	1,606,778	1,080,948	[bu]780,286	[ce]774,660	2,635,894
10	680,691	323,516	323,516	258,663	[bv]376,536	[cf]171,284	806,483
11	479,670	276,290	276,290	182,275	[bw](1,175,258)	[cg]127,882	(865,101)
12	0	215,677	215,677	0	0	[ch]642,989	642,989
13	0	2,592	2,592	0	0	0	0
14	0	0	0	0	145,559	0	145,559
15	0	399	399	0	0	[ci]614	614
16	0	0	0	0	418	0	418
17	0	205	205	0	0	[cj]358	358
18	0	322,576	322,576	0	0	[ck]347,132	347,132
19	0	3,888	3,888	0	0	[cl]4,184	4,184
20	0	876,032	876,032	0	0	[cm]942,719	942,719
21	0	2,018	2,018	0	0	[cn]3,382	3,382
22	0	11,077	11,077	0	0	[co]18,562	18,562
23	0	292	292	0	0	[cp]489	489
24	0	1,297	1,297	0	0	[cq]2,173	2,173
25	0	3,297	3,297	0	0	0	0
26	0	0	0	0	870,409	0	870,409
27	0	0	0	0	0	[cr]74	74
28	0	148	148	0	0	[cs]189	189
29	0	0	0	0	54	0	54
30	0	1,407	1,407	0	0	[ct]2,287	2,287
31	0	38,035	38,035	0	0	[cu]61,837	61,837
32	0	160	160	0	0	[cv]260	260
33	0	269	269	0	0	[cw]346	346
34	0	398	398	0	0	[cx]511	511
35	0	0	0	0	25,979	0	25,979
36	0	237	237	0	0	[cy]216	216

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
37	0	0	0	0	141	0	141
38	0	22,660	22,660	0	0	[(cz)]20,884	20,884
39	0	47,108	47,108	0	0	[(da)]43,415	43,415
40	0	10,547	10,547	0	0	[(db)]13,643	13,643
41	0	7,502	7,502	0	0	[(dc)]9,704	9,704
42	0	1,332	1,332	0	0	[(dd)]1,723	1,723
43	0	10	10	0	0	0	0
44	0	0	0	0	64,736	0	64,736
45	0	13,829	13,829	0	0	[(de)]84,124	84,124
46	0	1,688	1,688	0	0	[(df)]2,101	2,101
47	0	0	0	0	7,415	0	7,415
48	0	0	0	0	0	[(dg)]64	64
49	0	0	0	0	3	0	3
50	0	1,500	1,500	0	0	[(dh)]1,403	1,403
51	0	0	0	0	1,603	0	1,603
52	0	62,654	62,654	0	0	[(di)]101,050	101,050
53	0	1,213,586	1,213,586	0	0	[(dj)]1,957,305	1,957,305
54	0	256,837	256,837	0	0	[(dk)]414,234	414,234
55	0	250	250	0	0	[(dl)]1,239	1,239
56	0	460	460	0	0	[(dm)]2,280	2,280
57	0	4,216	4,216	0	0	[(dn)]20,899	20,899
58	0	182	182	0	0	0	0
59	0	0	0	0	1,162,640	0	1,162,640
60	0	49	49	0	0	[(do)]68	68
61	0	10,791	10,791	0	0	[(dp)]15,075	15,075
62	0	0	0	0	17,764	0	17,764
63	0	110	110	0	0	[(dq)]370	370
64	0	280	280	0	0	[(dr)]942	942
65	0	0	0	0	210	0	210
66	0	69,595	69,595	0	0	[(ds)]18,884	18,884
67	0	174,960	174,960	0	0	[(dt)]47,474	47,474
68	0	332	332	0	0	[(du)] [(dv)]451	451
69	0	3,241	3,241	0	0	[(dw)]4,408	4,408
70	0	8,340	8,340	0	0	[(dx)]11,342	11,342
71	0	4,202	4,202	0	0	[(dy)]5,714	5,714
72	0	636	636	0	0	0	0

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

Line No.	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Total Revenues ($) (k+l+m) (n)
73	0	0	0	0	184,751	0	184,751
74	0	550	550	0	0	(dz)769	769
75	0	554	554	0	0	(ea)775	775
76	0	3,784	3,784	0	0	(eb)5,294	5,294
77	0	0	0	0	3,960	0	3,960
78	0	150	150	0	0	(ec)140	140
79	0	0	0	0	61	0	61
80		0	0	0	0	(ed)64,299	64,299
81		0	0	0	0	(ee)64,299	64,299
82		0	0	0	0	(ef)70,729	70,729
83		0	0	0	0	(eg) (eh)70,729	70,729
84					(533,320)	(210,126)	(743,446)
35	4,286,090	6,238,700	6,235,221	1,687,088	1,607,219	6,984,011	10,278,318

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ 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: StatisticalClassificationCode

Contract with Bonneville Power Administration continues until terminated.

(c) Concept: StatisticalClassificationCode

Contract with Bonneville Power Administration continues until terminated.

(d) Concept: StatisticalClassificationCode

Contract with Bonneville Power Administration continues until terminated.

(e) Concept: StatisticalClassificationCode

Contract with Bonneville Power Administration continues until terminated.

(f) Concept: StatisticalClassificationCode

Contract with Bonneville Power Administration continues until terminated.

(g) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(h) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(i) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(j) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(k) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(l) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(m) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(n) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(o) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(p) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(q) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(r) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(s) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(t) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(u) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(v) Concept: StatisticalClassificationCode

Exchange agreement with PacifiCorp.

(w) Concept: StatisticalClassificationCode

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.

(x) Concept: StatisticalClassificationCode

Contract with Avista Corp expires on 01/01/2023.

(y) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(z) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(aa) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(ab) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(ac) Concept: StatisticalClassificationCode
Contract with Shell Energy North America (US) LP expires 01/01/2027.
(ad) Concept: StatisticalClassificationCode
Contract with Shell Energy North America (US) LP expires 01/01/2027.
(ae) Concept: StatisticalClassificationCode
Contract with Shell Energy North America (US) LP expires 01/01/2027.
(af) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ag) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(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 thePGE 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 thePGE OATT and settled financially under Schedule 11.
(aj) Concept: StatisticalClassificationCode
Contract with Constellation New Energy expires 01/01/2034.
(ak) Concept: StatisticalClassificationCode
Contract with Constellation New Energy expires 01/01/2034.
(al) Concept: StatisticalClassificationCode
Contract with Constellation New Energy expires 01/01/2034.
(am) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(an) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(ao) Concept: StatisticalClassificationCode
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.
(ap) Concept: StatisticalClassificationCode
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.
(aq) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ar) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(as) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(at) Concept: StatisticalClassificationCode
Contract with PacifiCorp expires 04/01/2027.
(au) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(av) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(aw) Concept: StatisticalClassificationCode

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(ax) Concept: StatisticalClassificationCode
Multiple contracts with PowerEx, the earliest of which expires 06/01/2023.
(ay) Concept: StatisticalClassificationCode
Multiple contracts with PowerEx, the earliest of which expires 06/01/2023.
(az) Concept: StatisticalClassificationCode
Multiple contracts with PowerEx, the earliest of which expires 06/01/2023.
(ba) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(bb) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(bc) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bd) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(be) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bf) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bg) Concept: StatisticalClassificationCode
Contract with The Energy Authority expires 01/01/2034.
(bh) Concept: StatisticalClassificationCode
Contract with The Energy Authority expires 01/01/2034.
(bi) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(bj) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(bk) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bl) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bm) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bn) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of thePGE OATT and settled financially under Schedule 11.
(bo) Concept: StatisticalClassificationCode
Contract with PUD No. 1 of Cowlitz County expires 01/01/2034.
(bp) Concept: StatisticalClassificationCode
Contract with PUD No. 1 of Franklin County expires 01/01/2034.
(bq) Concept: StatisticalClassificationCode
Contract with PUD No. 1 of Klickitat County expires 01/01/2034.
(br) Concept: StatisticalClassificationCode
Contract with PUD No. 1 of Lewis County expires 01/01/2034.
(bs) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's OpenAccess Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy ImbalanceMarket operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(bt) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's OpenAccess Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy ImbalanceMarket operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

(bu) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's OpenAccess Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy ImbalanceMarket operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(bv) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's OpenAccess Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy ImbalanceMarket operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(bw) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4R of PGE's OpenAccess Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy ImbalanceMarket operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.
(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services overagreed-upon facilities. The contract is evergreen.
(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services overagreed-upon facilities. The contract is evergreen.
(bz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services overagreed-upon facilities. The contract is evergreen.
(ca) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services overagreed-upon facilities. The contract is evergreen.
(cb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and PacifiCorp concerning the exchange of transmission services over agreed-upon facilities.
(cc) 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.
(cd) 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.
(ce) 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.
(cf) 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.
(cg) 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.
(ch) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.

(ci) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(co) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ct) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(da) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(db) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(de) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(df) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(di) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.
(dk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(do) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ds) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dt) 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.
(dw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ea) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(eb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ec) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ed) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ee) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(ef) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(eg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(eh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY MegaWatt Hours Received (c)	TRANSFER OF ENERGY MegaWatt Hours Delivered (d)
1	Bonneville Power Admin	(a) LFP		
2	Bonneville Power Admin	OS	233,003	233,003
3	Bonneville Power Admin	SFP	20,654	20,654
4	Bonneville Power Admin	NF	16,537	16,537
5	Avista Corp	NF	13,550	13,550
6	Columbia River PUD	SFP	12	12
7	Diversified Energy Transmission (DET)(Gamesa)	OS		
8	EDF Renewables	OS		
9	Eugene Water & Electric Board	(b) LFP	13	13
10	Idaho Power Co	NF	160,565	160,565
11	LA Dept of Water & Power	NF	28,726	28,726
12	McMinnville Water & Light	(c) LFP	986	986
13	Montana, State of	OS		
14	Nextera Energy Capital Holdings Inc	NF	9	9
15	Nevada Power Company	NF	57,340	57,340
16	NorthWestern Energy	NF	110,004	110,004
17	PacifiCorp	SFP	387,524	387,524
18	Puget Sound Energy	NF	220,720	220,720
19	Okanogan County PUD, Washington	NF	51,558	51,558
20	Seattle City Light	NF	2,025	2,025
21	UMATILLA ELECTRIC COOPERATIVE	NF	1	1
22	PacifiCorp, Linneman Substation	OS		
	TOTAL		1,303,227	1,303,227

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

Line No.	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Energy Charges ($) (f)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Other Charges ($) (g)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Total Cost of Transmission ($) (h)
1	79,270,640			79,270,640
2			[(d)] 16,438,465	16,438,465
3		1,430,613		1,430,613
4		193,869		193,869
5		83,828		83,828
6		18,614		18,614
7			[(e)] (953,746)	(953,746)
8			[(f)] (999,999)	(999,999)
9		116,448		116,448
10		530,598		530,598
11		180,197		180,197
12		10,160		10,160
13			[(g)] 1,751,109	1,751,109
14		1,528,258		1,528,258
15		395,761		395,761
16		793,605		793,605
17		745,836		745,836
18		418,810		418,810
19		76,295		76,295
20		2,938		2,938
21		50,000		50,000
22			[(h)] 60,522	60,522
	79,270,640	6,575,830	16,296,351	102,142,821

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Represents Bonneville Power Administration PTP contracts that have termination dates that range from 1/1/2021 - 1/1/2030.

(b) Concept: StatisticalClassificationCode

Represents Eugene Water & Electric Board contract which terminates on 12/1/2023.

(c) Concept: StatisticalClassificationCode

Represents McMinnville Water & Light contract which terminates on 12/31/2030.

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents Bonneville Power Administration Ancillary Transmission Services.

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents reduction in transmission expense from PGE assumption of GAMESA long-term PTP transmission capacity.

(f) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents reduction in transmission expense from PGE assumption of EDF long-term PTP transmission capacity.

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents Beneficial Use Tax and Wholesale Energy Transaction Tax payments to the State of Montana for use of BPA's transmission lines.

(h) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents PacifiCorp's Linneman Transmission Services.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,842,755
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,204,418
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,979,686
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	INVOLUNTARY SEVERANCE PROGRAM	3,466,987
7	DIRECTORS & OFFICERS EXPENSES	2,550,753
8	DIRECTORS FEES & EXPENSES	375,575
9	DIRECTORS PENSION	231,555
10	COLSTRIP- PPL MONTANA	700,592
11	MISC. ADMIN EXPENSES	377,585
46	TOTAL	15,729,906

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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

Line No.	A. Summary of Depreciation and Amortization Charges Functional Classification (a)	A. Summary of Depreciation and Amortization Charges Depreciation Expense (Account 403) (b)	A. Summary of Depreciation and Amortization Charges Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	A. Summary of Depreciation and Amortization Charges Amortization of Limited Term Electric Plant (Account 404) (d)	A. Summary of Depreciation and Amortization Charges Amortization of Other Electric Plant (Acc 405) (e)	A. Summary of Depreciation and Amortization Charges Total (f)
1	Intangible Plant			57,981,551		57,981,551
2	Steam Production Plant	20,334,752	2,662,698			22,997,450
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	22,416,738	(655)			22,416,083
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	80,791,138	875,293			81,666,431
7	Transmission Plant	21,067,422	(34,065)			21,033,357
8	Distribution Plant	132,833,930	(644,452)			132,189,478
9	Regional Transmission and Market Operation					
10	General Plant	41,352,614	(45,689)			41,306,925
11	Common Plant-Electric					
12	TOTAL	318,796,594	2,813,130	57,981,551		379,591,275

B. Basis for Amortization Charges

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

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	Applied depreciation rates for all assets effective 1/1/2018 per Order 17-365 in OPUC Docket UM-1809 except for the following accounts:						
13	348-Energy Storage Pilot	6.337	10 years	(5)%	10%	SQ	10 years
14	363-Energy Storage Pilot	1.151	10 years	(5)%	10%	SQ	10 years
15	390-Integrated Operations Center	159.515	60 years	(5)%	2.12%	R1.5	47 years

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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 (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO Department (f)	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO Account No. (g)
1	FERC:						
2	Docket RM06-16		117,393	117,393			
3	Docket RM06-22		49,001	49,001			
4	Docket ER22-233		529,590	529,590			
5	FERC matters less than $25,0000						
6	OPUC:						
7	OPUC Docket UM 1931		103,990	103,990			
8	OPUC Docket UE 394		298,861	298,861			
9	OPUC Docket UM 2032		144,431	144,431			
10	OPUC Docket UM 2074		648,381	648,381			
11	OPUC Docket UM 1971		87,979	87,979			
12	OPUC Docket AR 631		117,749	117,749			
13	OPUC Docket UM 2011		46,362	46,362			
14	OPUC matters less than $25,000		196,212	196,212			
15	Unassigned Non-Doc Matters		380,213	380,213			
46	TOTAL		2,720,162	2,720,162			

REGULATORY COMMISSION EXPENSES					
Line No.	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO Amount (h)	EXPENSES INCURRED DURING YEAR Deferred to Account 182.3 (i)	AMORTIZED DURING YEAR Contra Account (j)	AMORTIZED DURING YEAR Amount (k)	AMORTIZED DURING YEAR Deferred in Account 182.3 End of Year (l)
1					
2	117,393				
3	49,001				
4	529,590				
5					
6					
7	103,990				
8	298,861				
9	144,431				
10	648,381				
11	87,979				
12	117,749				
13	46,362				
14	196,212				
15	380,213				
46	2,720,162				

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)
1	A(6)	Electric R, D & D Performed Internally - Other	116,114	
2	B(1)	Electric R, D & D Performed Externally		1,747,706
3	B(4)	Electric R, D & D Performed Externally		469,559

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES			
	AMOUNTS CHARGED IN CURRENT YEAR	AMOUNTS CHARGED IN CURRENT YEAR	
Line No.	Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	930.2	116,114	
2	930.2	1,747,706	
3	930.2	469,559	

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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	29,948,180		
4	Transmission	7,573,024		
5	Regional Market			
6	Distribution	44,638,837		
7	Customer Accounts	24,456,377		
8	Customer Service and Informational	7,966,541		
9	Sales			
10	Administrative and General	82,241,735		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	196,824,694		
12	Maintenance			
13	Production	10,565,218		
14	Transmission	831,247		
15	Regional Market			
16	Distribution	29,450,000		
17	Administrative and General	1,218,349		
18	TOTAL Maintenance (Total of lines 13 thru 17)	42,064,814		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	40,513,398		
21	Transmission (Enter Total of lines 4 and 14)	8,404,271		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	74,088,837		
24	Customer Accounts (Transcribe from line 7)	24,456,377		
25	Customer Service and Informational (Transcribe from line 8)	7,966,541		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	83,460,084		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	238,889,508	24,439,982	263,329,490
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			

DISTRIBUTION OF SALARIES AND WAGES				
Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			0
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	238,889,508	24,439,982	263,329,490
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	66,138,348	24,991,772	91,130,120
69	Gas Plant			0
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	66,138,348	24,991,772	91,130,120
72	Plant Removal (By Utility Departments)			

DISTRIBUTION OF SALARIES AND WAGES

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
73	Electric Plant	2,242,808	24,317	2,267,125
74	Gas Plant			0
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,242,808	24,317	2,267,125
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	2,085,351	88,051	2,173,402
79	Co-Owner Shares of Generating Facilities	4,278,521	569,940	4,848,461
80	Other	12,872,260	614,935	13,487,195
81	Payroll Allocated	50,728,997	(50,728,997)	0
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	69,965,129	(49,456,071)	20,509,058
96	TOTAL SALARIES AND WAGES	377,235,793	0	377,235,793

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	1,685,689	4,082,570	6,425,812	[(a)]18,081,184
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	22,755,937	15,692,751	34,013,887	[(b)]108,610,584
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
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28					
29					
30					
31					
32					
33					
34					
35					

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS					
Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	24,441,626	19,775,321	40,439,699	126,691,768

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower
Represents purchases with ISO, netted by settlement invoice period and market.
(b) Concept: IsoOrRtoSettlementsEnergyNetSales
Represents sales with ISO, netted by settlement invoice period and market.

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PURCHASES AND SALES OF ANCILLARY SERVICES

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year Usage - Related Billing Determinant Number of Units (b)	Amount Purchased for the Year Usage - Related Billing Determinant Unit of Measure (c)	Amount Purchased for the Year Usage - Related Billing Determinant Dollar (d)
1	Scheduling, System Control and Dispatch	225,444	MWH	17,212,197
2	Reactive Supply and Voltage			
3	Regulation and Frequency Response			
4	Energy Imbalance	[(a)]110,027		[(b)] [(c)] [(d)] [(e)]3,746,414
5	Operating Reserve - Spinning			
6	Operating Reserve - Supplement			
7	Other			
8	Total (Lines 1 thru 7)	335,471		20,958,611

PURCHASES AND SALES OF ANCILLARY SERVICES

Line No.	Amount Sold for the Year Usage - Related Billing Determinant Number of Units (e)	Amount Sold for the Year Usage - Related Billing Determinant Unit of Measure (f)	Amount Sold for the Year Usage - Related Billing Determinant Dollars (g)
1	6,110,814	MWH	161,538
2	4,287,960	MWH	139,802
3	4,286,092	MWH	312,375
4	[f]78,139	MWH	[g]3,355,833
5	[h]3,506	MW	352,090
6	[i]3,506	MW	352,090
7			
8	14,770,017		4,673,728

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FOOTNOTE DATA

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

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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: Portland General Electric									
1	January	5,101	11	19	2,769	265	2,661	69	2,002	171
2	February	4,941	3	20	2,738	271	2,661	70	1,902	46
3	March	4,934	29	8	2,723	267	2,661	62	2,074	232
4	Total for Quarter 1				8,230	803	7,983	201	5,978	449
5	April	4,216	1	8	2,421	272	2,661	64	2,010	276
6	May	4,043	31	18	2,653	286	2,661	69	2,052	177
7	June	6,022	28	20	3,917	343	2,661	96	3,002	170
8	Total for Quarter 2				8,991	901	7,983	229	7,064	623
9	July	5,265	30	17	3,340	347	2,661	101	2,352	103
10	August	5,549	11	18	3,874	374	2,661	75	2,202	533
11	September	4,677	5	18	2,729	297	2,661	74	2,302	3
12	Total for Quarter 3				9,943	1,018	7,983	250	6,856	639
13	October	4,059	30	20	2,219	263	2,661	44	2,302	375
14	November	4,850	24	18	2,781	279	2,661	64	2,202	335
15	December	5,370	15	18	3,128	296	2,661	78	2,202	42
16	Total for Quarter 4				8,128	838	7,983	186	6,706	752
17	Total				35,292	3,560	31,932	866	26,604	2,463

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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)	18,296,054
3	Steam	2,059,539	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	0	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,483,976
5	Hydro-Conventional	1,073,224	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	26,630
7	Other	[(a)]11,621,337	27	Total Energy Losses	1,004,193
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	14,754,100	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	25,810,853
10	Purchases (other than for Energy Storage)	11,053,274			
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	6,238,700			
17	Delivered	6,235,221			
18	Net Transmission for Other (Line 16 minus line 17)	3,479			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	25,810,853			

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FOOTNOTE DATA

(a) Concept: OtherEnergyGeneration

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, CoyoteSprings, and Carty generation plants (as shown on page 403), and generation from PGE'ssolar generation facilities (as shown on page 410), other generation includes 2,312,776 megawatt hours of net wind energy from PGE's Biglow Canyon Wind Farm, Tucannon River Wind Farm and Wheatridge Wind Farm.

Actual gross wind generation from the wind farms was 2,320,278 megawatt hours.

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

In-service production cost at 12/31/2021: $938,355,162

Total installed capacity: 450 megawatts

Operations and maintenance expense for 2021: $12,955,425

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

In-service production cost at 12/31/2021: $486,874,188

Total installed capacity: 267 megawatts

Operations and maintenance expense for 2021: $9,640,203

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

In-service production cost at 12/31/2021: $152,689,913

Total installed capacity: 100 megawatts

Operations and maintenance expense for 2021: $3,017,497

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

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: Portland General Electric					
29	January	2,175,995	449,293	3,477	26	18
30	February	2,030,510	443,718	3,559	12	18
31	March	2,081,808	426,408	3,180	16	9
32	April	1,880,517	449,012	2,881	5	8
33	May	1,947,674	526,723	2,955	31	19
34	June	2,140,892	522,753	4,447	28	17
35	July	2,438,977	766,698	3,843	29	17
36	August	2,522,732	821,732	4,352	12	18
37	September	2,096,446	637,117	3,418	8	18
38	October	1,990,467	500,401	2,875	8	9
39	November	2,077,009	500,443	3,152	22	18
40	December	2,424,347	552,099	3,619	27	18
41	Total	25,807,374	6,596,397			

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: Beaver	Plant Name: Carty	Plant Name: [(a)] Colstrip	Plant Name: Coyote Springs	Plant Name: Port Westward 1	Plant Name: Port Westward 2
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)	573.2	503.1	311.2	296	483.3	225.1
6	Net Peak Demand on Plant - MW (60 minutes)	510	468	0	274	421	224
7	Plant Hours Connected to Load	3,999	7,511	0	7,201	7,851	6,065
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0	0
9	When Not Limited by Condenser Water	[(b)]533	0	0	[(c)]270	[(d)]421	225
10	When Limited by Condenser Water						
11	Average Number of Employees	43	30	0	31	28	0
12	Net Generation, Exclusive of Plant Use - kWh	836,944,000	3,004,886,000	2,067,933,000	1,722,865,000	2,915,248,000	825,784,000
13	Cost of Plant: Land and Land Rights	24,473	0	3,328,862	0	24,473	0
14	Structures and Improvements	37,795,579	86,552,377	116,665,202	11,585,593	43,090,969	42,471,958
15	Equipment Costs	231,406,885	441,268,421	383,784,125	186,714,916	247,606,459	261,095,975
16	Asset Retirement Costs	2,941,318	10,434,861	34,911,263	113,193	231,072	647,461
17	Total cost (total 13 thru 20)	272,168,255	538,255,659	538,689,452	198,413,702	290,952,973	304,215,394
18	Cost per KW of Installed Capacity (line 17/5) Including	474.8225	1,069.8781	1,731.0072	670.3166	602.0132	1,351.4678
19	Production Expenses: Oper, Supv, & Engr	470,910	404,856	(35,261)	366,713	723,602	18,638
20	Fuel	33,945,796	79,987,875	37,314,478	43,609,089	89,378,635	29,115,437

21	Coolants and Water (Nuclear Plants Only)	0	0	0	0	0	0
22	Steam Expenses	0	0	2,373,244	0	0	0
23	Steam From Other Sources						
24	Steam Transferred (Cr)	0	0	0	0	0	0
25	Electric Expenses	1,958,217	3,856,216	0	1,171,899	2,624,370	1,027,951
26	Misc Steam (or Nuclear) Power Expenses	1,782,863	1,660,770	2,970,490	753,168	1,508,021	405,216
27	Rents	217,035	0	0	80,866	28,586	33,347
28	Allowances	0	0	0	0	0	0
29	Maintenance Supervision and Engineering	1,461,125	206,236	815,410	40,091	283,032	28,411
30	Maintenance of Structures	126,963	8,868	824,949	61,431	19,077	1,607
31	Maintenance of Boiler (or reactor) Plant	0	0	7,590,866	0	0	0
32	Maintenance of Electric Plant	2,757,720	7,147,681	1,885,553	6,436,024	6,488,380	2,216,007
33	Maintenance of Misc Steam (or Nuclear) Plant	524,484	314,592	547,878	49,058	121,421	140,723
34	Total Production Expenses	43,245,113	93,587,094	54,287,607	52,568,339	101,175,124	32,987,337
35	Expenses per Net kWh	0.0517	0.0311	0.0263	0.0305	0.0347	0.0399

35	Plant Name	Beaver	Beaver	Carty	Coyote Springs	Port Westward 1	Port Westward 2
36	Fuel Kind	Gas	Oil	Gas	Gas	Gas	Gas
37	Fuel Unit	Mcf's	Barrels	Mcf's	Mcf's	Mcf's	Mcf's
38	Quantity (Units) of Fuel Burned	8,258,754	173	20,286,908	12,418,452	20,190,334	6,934,144
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	5.043		3.052	3.068	4.358	4.702
41	Average Cost of Fuel per Unit Burned	4.108	104.546	3.943	3.512	4.427	4.199
42	Average Cost of Fuel Burned per Million BTU	4.03	17.982	3.868	3.445	4.343	4.119
43	Average Cost of Fuel Burned per kWh Net Gen	0.041		0.027	0.025	0.031	0.035
44	Average BTU per kWh Net Generation	[e]10,060.074		[f]6,882.066	[g]7,347.629	[h]7,059.907	[i]8,559.677

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: NetContinuousPlantCapabilityNotLimitedByCondenserWater
Based on January average temperature.
(c) Concept: NetContinuousPlantCapabilityNotLimitedByCondenserWater
Based on January average temperature.
(d) Concept: NetContinuousPlantCapabilityNotLimitedByCondenserWater
Based on January average temperature.
(e) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.
(f) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.
(g) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.
(h) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.
(i) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

Hydroelectric Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 2195 Plant Name: Faraday	FERC Licensed Project No. 2195 Plant Name: North Fork	FERC Licensed Project No. 2195 Plant Name: Oak Grove	FERC Licensed Project No. 2030 Plant Name: [(a)] Pelton	FERC Licensed Project No. 2030 Plant Name: [(b)] Pelton (PGE%)	FERC Licensed Project No. 2195 Plant Name: River Mill	FERC Licensed Project No. 2030 Plant Name: [(c)] Round Butte	FERC Licensed Project No. 2030 Plant Name: [(d)] Round Butte (PGE%)	FERC Licensed Project No. 2233 Plant Name: Sullivan
1	Kind of Plant (Run-of-River or Storage)	Run-of River;Storage	Run-of River	Run-of River	Storage	Storage	Run-of River	Storage	Storage	Run-of River
2	Plant Construction type (Conventional or Outdoor)	Conventional; Outdoor	Outdoor	Conventional	Outdoor	Outdoor	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1907	1958	1924	1957	1957	1911	1964	1964	1895
4	Year Last Unit was Installed	1958	1958	1931	1958	1958	1952	1964	1964	1953
5	Total installed cap (Gen name plate Rating in MW)	36.8	50.3	51	110.2	73.5	20.6	372.5	248.3	15.4
6	Net Peak Demand on Plant-Megawatts (60 minutes)	[(e)]0	57	2	103	0	25	227	0	18
7	Plant Hours Connect to Load	[(f)] [(g)]0	8,753	1	8,641	0	8,738	8,700	0	8,597
8	Net Plant Capability (in megawatts)									
9	(a) Under Most Favorable Oper Conditions	46	58	44	110	0	25	345	0	18
10	(b) Under the Most Adverse Oper Conditions	5	7	19	60	0	4	192	0	7
11	Average Number of Employees	53	0	2	[(h)]0	0	0	[(i)]40	0	1
12	Net Generation, Exclusive of Plant Use - kWh	[(j)](10,000)	163,957,000	(14,000)	327,810,000	218,540,000	85,273,000	750,703,500	500,469,000	105,009,000
13	Cost of Plant									

14	Land and Land Rights	33,434	377,100	9,457	3,681,439	2,454,415	86,408	3,726,481	2,521,012	572,077
15	Structures and Improvements	19,042,417	9,305,852	17,358,631	10,144,175	6,773,940	7,518,906	18,813,677	12,582,236	19,611,993
16	Reservoirs, Dams, and Waterways	33,265,532	85,618,073	27,359,829	15,710,616	10,705,389	58,745,880	172,059,152	112,446,611	31,499,172
17	Equipment Costs	11,588,158	13,289,180	23,797,854	23,604,971	15,989,690	15,047,060	40,491,984	(k)178,775,754	14,507,819
18	Roads, Railroads, and Bridges	2,441,325	2,837,601	5,682,892	6,252,252	4,428,933	475,899	2,564,266	1,794,841	0
19	Asset Retirement Costs	90	6	2,122	52	52	64	164	164	2,630
20	Total cost (total 13 thru 20)	66,370,956	111,427,812	74,210,785	59,393,505	40,352,419	81,874,217	237,655,724	308,120,618	66,193,691
21	Cost per KW of Installed Capacity (line 20 / 5)	1,803.5586	2,215.2647	1,455.1134	538.961	549.0125	3,974.4766	638.0019	1,240.9207	4,298.2916
22	Production Expenses									
23	Operation Supervision and Engineering	184,848	19,373	22,301	288,154	189,281	19,843	380,549	259,703	3,361
24	Water for Power	69,189	54,376	67,736	173,449	97,538	44,995	332,676	239,896	37,258
25	Hydraulic Expenses	1,143,036	302,620	1,844,690	2,695,395	1,851,070	410,996	2,988,148	1,956,195	194,096
26	Electric Expenses	652,977	308,954	193,444	317,532	208,989	74,190	406,158	273,495	233,819
27	Misc Hydraulic Power Generation Expenses	1,358,690	386,653	555,838	902,145	573,370	178,380	1,289,907	888,071	247,433
28	Rents	200,378	124,187	866,440	13,351	5,784	0	37,101	27,852	0
29	Maintenance Supervision and Engineering	448,023	0	101,381	94,087	76,310	3,532	24,440	2,712	0
30	Maintenance of Structures	0	0	0	0	0	0	0	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	10,330	11,130	23,030	70,716	29,179	4,126	206,225	155,458	170,895
32	Maintenance of Electric Plant	37,619	46,828	214,738	221,257	121,116	464,972	446,417	324,022	205,106
33	Maintenance of Misc Hydraulic Plant	860,720	233,339	178,595	274,867	185,602	46,767	320,294	211,192	41,484
34	Total Production Expenses (total 23 thru 33)	4,965,810	1,487,460	4,068,193	5,050,953	3,338,239	1,247,801	6,431,915	4,338,596	1,133,452
35	Expenses per net kWh	(496.581)	0.0091	(290.5852)	0.0154	0.0153	0.0146	0.0086	0.0087	0.0108

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: PlantName
Respondent is the principal owner (66.67% interest) and operator of the plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon. Reported here are 100% costs and plant statistics, including shared and non-shared costs.
(b) Concept: PlantName
Jointly owned. Reported here are respondents 66.67% share of installed capacity, cost of plant, net generation and production expenses.
(c) Concept: PlantName
Respondent is the principal owner (66.67% interest) and operator of the plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon. Reported here are 100% costs and plant statistics, including shared and non-shared costs.
(d) Concept: PlantName
Jointly owned. Reported here are respondents 66.67% share of installed capacity, cost of plant, net generation and production expenses.
(e) Concept: NetPeakDemandOnPlant
Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.
(f) Concept: PlantHoursConnectedToLoad
Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.
(g) Concept: PlantHoursConnectedToLoad
Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.
(h) Concept: PlantAverageNumberOfEmployees
All employees are reported at the Round Butte Location, which includes Pelton. Round Butte and Pelton are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.
(i) Concept: PlantAverageNumberOfEmployees
This number includes Pelton. Round Butte and Pelton are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.
(j) Concept: NetGenerationExcludingPlantUse
Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.
(k) Concept: EquipmentCostsHydroelectricProduction
Includes an impact of modification of hydro project capital lease agreement which extended the term of the lease by 16 years as well as regular activities of capitalized lease assets.

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	Maclaren	1999	0.5	0.4	43	133,799
2	Oregon Military Dept/A.F.R.C.	2001	1.6	1.6	30	192,125
3	US Bank Corp Columbia Center	2001	6.4	6.2	129	488,057
4	Portland State University	2004	2.8	2.8	20	261,802
5	Oregon Military Joint Forces HQ	2005	1.6	1.6	26	191,439
6	Stimson Lumber	2005	0.57	0.51	8	159,546
7	Flexential (Formerly ViaWest/Fortix)	2005	14	12.4	401	644,709
8	Skyline	2005	2	1.8	33	201,526
9	Tri-Quint	2005	0.6	0.54	1	109,968
10	NCCWC Filter Plant	2005	2	1.8	83	122,958
11	PCC Structurals	2005	1	0.9	12	113,874
12	Providence Portland Medical Center	2005	6	5.4	173	265,383
13	Salem Hospital	2006	8	7.2	195	269,108
14	Sunrise Water Authority Pump Station	2006	1.25	1.13	11	88,272
15	Providence Newberg Hospital	2006	1.5	1.35	29	156,833
16	vXchnge (Formerly Sungard DSG)	2006	2	1.8	47	331,845
17	Kaiser Sunnyside Hospital	2007	4.5	4.05	138	352,752
18	Newberg Waste Water Treatment Plant	2008	2	1.8	33	154,458
19	Xerox Corp	2007	4	3.6	58	384,805
20	Newberg Water Treatment Plant	2007	1	0.9	17	78,159
21	Oregon Dept of Admin Serv - Data Center	2010	3.86	3.47	61	332,026
22	Panasonic (Formerly Sanyo)	2010	1	0.9	17	43,144
23	Sysco Foods	2010	2	1.8	29	184,779
24	Clackamas Intertie 2	2012	0.6	0.54	14	155,832
25	Dawson Creek	2012	0.8	0.72	9	95,706
26	Kaiser Westside Hospital	2012	4	3.6	70	408,830
27	North Plains Pump Station	2012	0.8	0.72	7	53,132
28	Oak Lodge Sanitary District	2012	2	1.8	32	229,144
29	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.5	1.25	22	284,255
30	Oregon State Hospital	2012	4	3.6	128	172,879
31	Portland Service Center	2012	0.5	0.45	5	322,856
32	Sandy Highschool	2012	1.25	1.13	42	179,894
33	TATA Communications - Hillsboro	2012	4.5	4.05	41	328,979
34	Tri-City Wastewater Treatment Plant	2012	2.5	2.25	57	161,695
35	TATA Communications - Portland	2013	6	5.4	88	612,983

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)
36	City of Hillsboro Crandall Reservoir	2013	0.8	0.72	8	105,854
37	East County Courts	2013	1.5	1.35	25	316,848
38	City of Portland-Columbia Blvd WWTP	2013	1	0.9	14	162,234
39	Food Services of America	2013	2	1.8	80	230,330
40	Avery DSG	2014	0.8	0.72	22	263,782
41	Carver (Readiness Center) DSG	2014	2	1.8	31	818,635
42	Juvenile Justice Center	2014	0.75	0.68	12	171,531
43	Clackamas River Water DSG	2014	2	1.8	53	383,436
44	Joint Water Commission	2015	5	4.5	81	190,302
45	McLane Foodservice	2016	1.5	1.35	73	183,432
46	Flexential Brookwood (Formerly ViaWest Brookwood)	2016	16.25	14.63	962	278,175
47	World Trade Center	2017	3.2	2.88	42	1,021,168
48	Washington County Jail	2017	1.5	1.35	19	325,578
49	OHSU - Vaccine Gene Therapy Institute	2017	1.5	1.25	13	366,768
50	OHSU - Center for Health & Healing	2018	3	2.7	86	351,605
51	OHSU - Knight Cancer Research Building	2018	2	1.8	26	237,298
52	Hattan Road Pump Station - HRPS	2021	1	0.9	4	212,306
53	Beaverton Public Service Center DSG	2021	1	0.9		518,065
54	Solar	2014	3.019	3.019	2,834	725,380

GENERATING PLANT STATISTICS (Small Plants)						
Line No.	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel Production Expenses (i)	Production Expenses Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
1	267,598		5,609	7,020	diesel-low	2,218
2	120,078		9,495	66,465	diesel-low	1,708
3	76,259		93,837	99,701	diesel-low	1,874
4	93,501		13,349	49,833	diesel-low	1,586
5	119,649		9,361	32,474	diesel-low	1,772
6	279,905		720	2,678	diesel-low	1,727
7	46,051		37,168	306,526	diesel-low	1,702
8	100,763			14,080	diesel-low	2,113
9	183,280			4,349	diesel-low	1,791
10	61,479		16,005	21,718	diesel-low	2,084
11	113,874		1,415	6,860	diesel-low	1,980
12	44,231		25,024	78,505	diesel-low	1,884
13	33,639		24,830	74,167	diesel-low	1,791
14	70,618			23,510	diesel-low	2,149
15	104,555			33,166	diesel-low	2,094
16	165,923		9,207	17,135	diesel-low	1,774
17	78,389		53,179	63,215	diesel-low	1,943
18	77,229		5,186	13,286	diesel-low	1,865
19	96,201		8,377	6,377	diesel-low	1,919
20	78,159		2,604	7,703	diesel-low	1,873
21	86,017		7,101	39,720	diesel-low	1,278
22	43,144		4,371	5,982	diesel-low	1,829
23	92,390		9,062	17,791	diesel-low	2,000
24	259,720		1,444	16,575	diesel-low	1,791
25	119,633			4,801	diesel-low	1,791
26	102,208		9,872	43,632	diesel-low	1,793
27	66,415			18,327	diesel-low	1,791
28	114,572		4,311	8,609	diesel-low	1,694
29	189,503		2,821	11,620	diesel-low	1,654
30	43,220			26,722	diesel-low	1,508
31	645,712			7,260	diesel-low	1,791
32	143,915		10,706	20,981	diesel-low	1,732
33	73,106			57,349	diesel-low	2,272
34	64,678		7,546	7,116	diesel-low	1,911
35	102,164		11,633	67,405	diesel-low	1,283
36	132,318			2,678	diesel-low	1,791
37	211,232		4,857	14,873	diesel-low	1,837
38	162,234		3,305	8,390	diesel-low	1,696

GENERATING PLANT STATISTICS (Small Plants)						
Line No.	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel Production Expenses (i)	Production Expenses Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
39	115,165		8,578	35,497	diesel-low	1,828
40	329,728			6,691	diesel-low	1,791
41	409,318		5,471	37,617	diesel-low	1,235
42	228,708			22,719	diesel-low	1,791
43	191,718		11,776	22,449	diesel-low	2,081
44	38,060		18,497	25,123	diesel-low	1,560
45	122,288		7,218	20,629	diesel-low	1,786
46	17,118		42,861	143,472	diesel-low	1,840
47	319,115		5,646	67,981	diesel-low	1,608
48	217,052		8,427	33,940	diesel-low	1,516
49	244,512		1,385	16,441	diesel-low	1,793
50	117,202		11,594	32,068	diesel-low	2,078
51	118,649		5,520	29,056	diesel-low	2,117
52	212,306		2,518	8,800	diesel-low	1,791
53	518,065		1,532	6,948	diesel-low	1,211
54	240,272	543,517		18,238	solar	

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
34	Other
35	Other
36	Other
37	Other
38	Other
39	Other

GENERATING PLANT STATISTICS (Small Plants)	
Line No.	Generation Type (m)
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
54	Solar

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structures of Another Line (g)	Number of Circuits (h)
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	16.82		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
21	[(j)] 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	8.98		2
26	CARVER	GRESHAM #1	230	230	H-WOOD	7.39		1

TRANSMISSION LINE STATISTICS

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structures of Another Line (g)	Number of Circuits (h)
27	CARVER	McLOUGHLIN #1	230	230	H-WOOD/ST. MONOP	4.92		1
28	CARVER	McLOUGHLIN #2	230	230	ST. MONOP	4.88		1
29	CENTRAL FERRY BPA	MULLAN (TUCANNON WF)	230	230	H-WOOD	20.7		1
30	DALREED PACW	[q] CARTY	230	230	H-WOOD	16.76		1
31	[l] GRESHAM	TROUTDALE PACW #1	230	230	H-WOOD	0.43		1
32	GRESHAM	TROUTDALE PACW #2	230	230	ST. TOWER	0.33		1
33	HARBORTON	RIVERGATE #1	230	230	ST. TOWER/H-WOOD	1.53		1
34	HARBORTON	TROJAN #1	230	230	ST TOWER	33.6		2
35	HORIZON	KEELER BPA	230	230	ST. MONOP	1.47		2
36	HORIZON	ST. MARYS - TROJAN	230	230	ST. TOWER/ST. MONOP	12.55	32.65	1
37	[m] KEELER BPA	RIVERGATE	230	230	ST. TOWER	0.1		2
38	KEELER BPA	ST. MARYS	230	230	H-WOOD/ST. TOWER	6.67		2
39	McLOUGHLIN	PEARL BPA - SHERWOOD	230	230	ST. TOWER/ST. MONOP	16.38	4.7	2
40	MURRAYHILL	SHERWOOD #1	230	230	ST. TOWER	5.58		2
41	MURRAYHILL	SHERWOOD #2	230	230	ST. TOWER		5.58	2
42	MURRAYHILL	ST. MARYS	230	230	ST. TOWER	5.22		2
43	[n] PEARL BPA	SHERWOOD	230	230	ST. MONOP/ST. TOWER/H-WOOD	4.88		1
44	[o] PELTON	ROUND BUTTE	230	230	H-WOOD	7.87		1
45	PORT WESTWARD	TROJAN #1	230	230	H-WOOD/ST. MONOP	18.78		1
46	PORT WESTWARD	TROJAN #2	230	230	H-WOOD/ST. MONOP	9.39	9.39	2
47	REDMOND BPA	ROUND BUTTE	230	230	H-WOOD	23.58		1
48	[p] RIVERGATE	ROSS BPA	230	230	ST. TOWER	0.09		2
49	ROUND BUTTE	GENERATOR #1	230	230	ST. TOWER	0.54		1
50	ROUND BUTTE	GENERATOR #2	230	230	ST. TOWER	0.54		1
51	ROUND BUTTE	GENERATOR #3	230	230	ST. TOWER	0.54		1
52	TOTAL 230KV LINES							
53	ALL 115KV LINES					437.67		

TRANSMISSION LINE STATISTICS								
	DESIGNATION	DESIGNATION	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		LENGTH (Pole miles) - (In the case of underground lines report circuit miles)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)	
Line No.	From (a)	To (b)	Operating (c)	Designated (d)	Type of Supporting Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
54	ALL 57KV LINES					11.81		
36	TOTAL					1,517.87	53.66	60

TRANSMISSION LINE STATISTICS									
		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
Line No.	Size of Conductor and Material (i)	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	85,806,325	87,332,935	495,234	236,618	2,350,107	3,081,959
15				0				0
16	2156 ACSS			0				0
17	1272 AAC			0				0
18	1272 AAC/1272 ACSR			0				0
19	795 ACSR			0				0
20	1780 ACSR			0				0
21	2388 AAC TW			0				0
22	1272 ACSS			0				0
23	1272 ACSS			0				0
24	1272 ACSS			0				0
25	1272 AAC			0				0
26	1272 AAC			0				0
27	1272 AAC			0				0
28	1272 ACSS			0				0
29	954 ACSR			0				0
30	795 AAC			0				0
31	954 ACSR			0				0
32	1272 AAC			0				0
33	1272 AAC			0				0
34	1590 AAC			0				0
35	1272 ACSS			0				0
36	1590 AAC			0				0

TRANSMISSION LINE STATISTICS									
		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
Line No.	Size of Conductor and Material	Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
37	1272 AAC			0				0
38	1590 ACSR TWD			0				0
39	2-1272 AAC/1272 AAC/2-1780 ACSR			0				0
40	1272 AAC			0				0
41	1272 AAC			0				0
42	1272 ACSS			0				0
43	2-2388 AAC TW			0				0
44	795 ACSR			0				0
45	2156 ACSS			0				0
46	2156 ACSS			0				0
47	795 ACSR			0				0
48	795 ACSR			0				0
49	795 ACSR			0				0
50	795 ACSR			0				0
51	795 ACSR			0				0
52		8,608,271	131,092,662	139,700,933	677,944	259,426	803,072	1,740,442
53		1,036,894	169,732,801	170,769,695	1,711,465	1,298,342	0	3,009,807
54				0				0
36		11,171,775	386,631,788	397,803,563	2,884,643	1,794,386	3,153,179	7,832,208

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

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

(b) Concept: TransmissionLineStartPoint

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

(c) Concept: TransmissionLineStartPoint

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

(d) Concept: TransmissionLineStartPoint

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

(e) Concept: TransmissionLineStartPoint

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

(f) Concept: TransmissionLineStartPoint

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

(g) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacity conductor on this line. PGE has certain capacity responsibilities in conjunction with the500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire mileage not reported as BPA is owner/operator of this section of Transmission Line.

(h) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction(CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased linecapacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacityconductor on this line. PGE has certain capacity responsibilities in conjunction with the500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 TransmissionOverhead Conductors and Devices. Wire Mileage is not reported here as BPA isowner/operator of this portion of the Transmission Line.

(i) Concept: TransmissionLineStartPoint

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

(j) Concept: TransmissionLineStartPoint

Portland General Electric made payment in the form of Contribution in Aid of Construction(CIAC) in 2007 to Bonneville Power Administration. PGE recorded the CIAC to FERC accounts355 Transmission Poles and Fixtures, 356 Transmission Overhead Conductors and Devices.Wire mileage is not reported here as BPA is owner/operator of these transmission lines.

(k) Concept: TransmissionLineStartPoint

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

(l) Concept: TransmissionLineStartPoint

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

(m) Concept: TransmissionLineStartPoint

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

(n) Concept: TransmissionLineStartPoint

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

(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'sshare.

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION LINES ADDED DURING YEAR

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)
1	Horizon	Sunset #3	0.09	Wood Pole	2	1
44	TOTAL		0.09		2	1

TRANSMISSION LINES ADDED DURING YEAR						
Line No.	CIRCUITS PER STRUCTURE Ultimate (g)	CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)
1	1	2156 ACSS			115	
44	1					0

TRANSMISSION LINES ADDED DURING YEAR					
Line No.	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Construction (q)
1	212,853			212,853	
44	212,853	0	0	212,853	

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
1	9 Substation Under 10 MVa capacity	Distribution	Unattended				69
2	Abernethy, Oregon City, OR	Distribution	Unattended	115	13		44.8
3	Alder, Portland, OR	[ae] Transmission	Unattended	115	13		56
4	Amity, near Amity, OR	Distribution	Unattended	57	13		15
5	Arleta, Portland, OR	Distribution	Unattended	57	13		42
6	[a] Bakeoven, BPA, Near Bakeoven, OR	Transmission	Unattended	500			
7	Banks, Banks, OR	Distribution	Unattended	57	13		20
8	Barnes, Salem, OR	Distribution	Unattended	115	13		42
9	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	13		464
10	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	24		170
11	Beaverton, Beaverton, OR	[af] Transmission	Unattended	115	13		34
12	Bell, near Portland, OR	[ag] Transmission	Unattended	115	13		66
13	Bethany, Portland, OR	[ah] Transmission	Unattended	115	13		56
14	Bethel, Salem, OR	[ai] Transmission	Unattended	230	115	13	564
15	Bethel, Salem, OR	[aj] Transmission	Unattended	115	57	13	140
16	Bethel, Salem, OR	[ak] Transmission	Unattended	115	13		28
17	Biglow Canyon Windfarm	Transmission	Unattended	230	34.5	13	480
18	Blue Lake, Troutdale, OR	[al] Transmission	Unattended	230	115	13	640
19	Blue Lake, Troutdale, OR	[am] Transmission	Unattended	115	13		56
20	Boones Ferry, Lake Oswego, OR	[an] Transmission	Unattended	115	13		50
21	Boring, near Boring, OR	Distribution	Unattended	57	13		24
22	[b] Broadview Subst. near Broadview, MT	Transmission	Unattended	500	230		80
23	Brookwood, near Hillsboro, OR	Distribution	Unattended	57	13		28
24	[c] Buckley, BPA near Buckley, WA	Transmission	Unattended	500			
25	Butler, Hillsboro OR	[ao] Transmission	Unattended	115	13		300
26	Canby, near Barlow, OR	Distribution	Unattended	57	13		39

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation Transmission or Distribution (b)	Character of Substation Attended or Unattended (b-1)	VOLTAGE (In MVa) Primary Voltage (In MVa) (c)	VOLTAGE (In MVa) Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa) Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
27	Canemah, Oregon City, OR	[ap] Transmission	Unattended	115	57	13	250
28	Canyon, Portland, OR	[aq] Transmission	Unattended	115	13		200
29	[d] Captain Jack, BPA, Near Malin, OR	Transmission	Unattended	500			
30	Carty, near Boardman, OR	Transmission	Unattended	500	21		596
31	Carty, near Boardman, OR	Transmission	Unattended	16	7.2	4.2	22
32	Carver, Carver, OR	[ar] Transmission	Unattended	230	115	13	640
33	Carver, Carver, OR	[as] Transmission	Unattended	115	13		56
34	Cascade, St Helens, OR	Distribution	Unattended	115	13		48
35	Cedar Hills, near Beaverton, OR	Distribution	Unattended	115	13		56
36	Centennial, near Gresham, OR	Distribution	Unattended	115	13		56
37	[e] Chemawa BPA, near Salem, OR	Distribution	Unattended	115			
38	[f] Chemawa BPA, near Salem, OR	Distribution	Unattended	57			
39	Clackamas, Clackamas, OR	[at] Transmission	Unattended	115	13		41
40	Claxtar, Salem,OR	Distribution	Unattended	57	13		28
41	Coffee Creek, Sherwood, OR	Distribution	Unattended	115	13		28
42	[g] Colstrip Plant, near Colstrip, MT	Transmission	Unattended	500	26		164
43	[h] Colstrip Subst. near Colstrip, MT	Transmission	Unattended	500	230		100
44	Cornelius, Cornelius, OR	[au] Transmission	Unattended	57	13		28
45	Cornelius, Cornelius, OR	[av] Transmission	Unattended	115	57	13	140
46	Cornell, Portland, OR	Distribution	Unattended	115	13		28
47	[i] Coyote Springs, Boardman, OR	Transmission	Unattended	500			300
48	Culver, Salem, OR	[aw] Transmission	Unattended	115	13		28
49	Curtis, Portland, OR	[ax] Transmission	Unattended	115	13		17
50	Dayton, near Dayton , OR	[ay] Transmission	Unattended	57	13		20
51	Dayton, near Dayton , OR	[az] Transmission	Unattended	115	57	13	125
52	Delaware, Portland, OR	[ba] Transmission	Unattended	115	13		28
53	Denny, Beaverton, OR	[bb] Transmission	Unattended	115	13		56

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
54	Dilley, near Forest Grove, OR	Distribution	Unattended	57	13		13
55	Dunn's Corner, near Sandy,OR	[bc] Transmission	Unattended	57	13		14
56	Durham, Tigard , OR	Distribution	Unattended	115	13		56
57	E., Portland, OR	[bd] Transmission	Unattended	115	13		208
58	E., Portland, OR	[be] Transmission	Unattended	115	11		132
59	Eagle Creek, Eagle Creek, OR	Distribution	Unattended	57	13		14
60	Eastport, Portland, OR	[bf] Transmission	Unattended	115	13		17
61	Elma, near Salem, OR	Distribution	Unattended	57	13		56
62	Estacada, Estacada, OR	Distribution	Unattended	57	13		30
63	Fairmount, Salem, OR	[bg] Transmission	Unattended	115	13		25
64	Fairview, Fairview, OR	[bh] Transmission	Unattended	115	13		50
65	Faraday Plant, near Estacada, OR	[bi] Transmission	Unattended	115	13		27
66	Faraday, Switchyard, OR	[bj] Transmission	Unattended	115	57	13	140
67	Faraday, Switchyard, OR	[bk] Transmission	Unattended	57	11		32
68	[j] Forest Grove BPA, Forest Grove, OR	Transmission	Unattended	115			
69	[k] Fort Rock, 12 mi NE of Silver Lake, OR	Transmission	Unattended	500			
70	Garden Home, near Portland, OR	Distribution	Unattended	115	13		28
71	Glencoe, Portland, OR	Distribution	Unattended	115	13		25
72	Glencullen, Portland, OR	[bl] Transmission	Unattended	115	13		24
73	Glendoveer, near Portland, OR	[bm] Transmission	Unattended	115	13		50
74	Glisan, Gresham, OR	[bn] Transmission	Unattended	115	13		45
75	Grand Ronde, Grand Ronde, OR	[bo] Transmission	Unattended	115	57	13	33
76	Grand Ronde, Grand Ronde, OR	[bp] Transmission	Unattended	115	13		13
77	Grasslands, near Boardman, OR	Transmission	Unattended	500			
78	Gresham, near Gresham, OR	Transmission	Unattended	230	115	13	572
79	[l] Grizzly, BPA, near Madras, OR	Transmission	Unattended	500			
80	Harborton, near Portland, OR	[bq] Transmission	Unattended	230	115	13	373

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation Transmission or Distribution (b)	Character of Substation Attended or Unattended (b-1)	VOLTAGE (In MVa) Primary Voltage (In MVa) (c)	VOLTAGE (In MVa) Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa) Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
81	Harmony, near Milwaukie, OR	Distribution	Unattended	115	13		50
82	Harrison Sub, Portland, OR	[br] Transmission	Unattended	115	13		28
83	Hayden Island, near Portland, OR	Distribution	Unattended	115	13		34
84	Helvetia, Hillsboro, OR	[bs] Transmission	Unattended	115	34.5		100
85	Hemlock, Portland, Or	Distribution	Unattended	115	13		28
86	Hillcrest, Salem , OR	[bt] Transmission	Unattended	115	13		28
87	Hillsboro, Hillsboro , OR	Distribution	Unattended	57	13		43
88	Hogan North, Gresham, OR	Distribution	Unattended	115	13		56
89	Hogan South, Gresham, OR	[bu] Transmission	Unattended	115	57	13	125
90	Hogan South, Gresham, OR	[bv] Transmission	Unattended	115	13		56
91	Holgate, Portland, OR	Distribution	Unattended	57	13		39
92	Horizon, Hillsboro, OR	Transmission	Unattended	230	115	13	960
93	Huber, near Beaverton, OR	Distribution	Unattended	115	13		56
94	Indian, near Salem, OR	[bw] Transmission	Unattended	115	13		56
95	Island, near Milwaukie, OR	[bx] Transmission	Unattended	115	13		45
96	Jennings Lodge, Jennings Lodge, OR	Distribution	Unattended	115	13		53
97	[m] Keeler, BPA, Hillsboro, OR	Transmission	Unattended				
98	Kelley Point, Portland, OR	Distribution	Unattended	115	13		56
99	Kelly Butte, Portland, OR	[by] Transmission	Unattended	115	13		45
100	King City, near King City, OR	[bz] Transmission	Unattended	115	13		56
101	Leland, Oregon City, OR	Distribution	Unattended	57	13		28
102	Lents, near Portland, OR	Distribution	Unattended	115	13		22
103	Lents, near Portland, OR	Distribution	Unattended	57	11		20
104	Liberty, Salem, OR	[ca] Transmission	Unattended	115	13		50
105	Main, Hillsboro, OR	Distribution	Unattended	57	13		84
106	[n] Malin, BPA, near Malin, OR	Transmission	Unattended	500			
107	Market, Salem, OR	[cb] Transmission	Unattended	115	13		28
108	Marquam, Portland OR	[cc] Transmission	Unattended	115	13		250
109	McClain, Salem, OR	Distribution	Unattended	57	13		23

SUBSTATIONS							
		Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	
Line No.	Name and Location of Substation (a)	Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
110	McGill, Gresham, OR	[cd] Transmission	Unattended	115	13		75
111	McLoughlin, near Oregon City, OR	[ce] Transmission	Unattended	230	115	13	640
112	Meridian, near Tualatin, OR	[cf] Transmission	Unattended	115	13		84
113	Middle Grove, near Middle Grove, OR	Distribution	Unattended	115	13		53
114	Midway, near Portland, OR	Distribution	Unattended	115	13		34
115	Mill Creek, near Salem, OR	[cg] Transmission	Unattended	115	13		17
116	Mobile No. 1, OR	Distribution	Unattended	115	57	13	15
117	Mobile No. 2, OR	Distribution	Unattended	115	57	13	34
118	Mobile No. 3, OR	Distribution	Unattended	115	57	13	29
119	Mobile No. 4 OR	Distribution	Unattended	115	57	13	34
120	Mobile No. 5 OR	Distribution	Unattended	115	57	13	34
121	Mobile No. 6 OR	Distribution	Unattended	115	57	13	34
122	Mobile No. 7 OR	Distribution	Unattended	115	57	13	25
123	Mobile No. 8 OR	Distribution	Unattended	115	57	13	25
124	Molalla, Molalla, OR	Distribution	Unattended	57	13		42
125	Monitor, near Monitor, OR	[ch] Transmission	Unattended	230	57	13	125
126	Mt. Angel, Mt. Angel, OR	Distribution	Unattended	57	13		20
127	Mt. Pleasant, Oregon City , OR	Distribution	Unattended	115	13		45
128	Multnomah, Portland, OR	Distribution	Unattended	115	13		39
129	Murrayhill, Beaverton, OR	[ci] Transmission	Unattended	115	13		56
130	Murrayhill, Beaverton, OR	[cj] Transmission	Unattended	230	115	13	320
131	Newberg, Newberg, OR	[ck] Transmission	Unattended	115	13		45
132	North Fork, near Estacada, OR	Transmission	Unattended	115	13	0.48	53
133	North Marion, near Woodburn, OR	Distribution	Unattended	57	13		31
134	North Plains, North Plains, OR	Distribution	Unattended	57	13		20
135	Northern, Portland, OR	Distribution	Unattended	57	11		28
136	Oak Grove, Three Lynx, OR	[cl] Transmission	Unattended	115	13		8
137	Oak Grove, Three Lynx, OR	[cm] Transmission	Unattended	115	11		64
138	Oak Grove, Three Lynx, OR	[cn] Transmission	Unattended	13	11		
139	Oak Grove, Three Lynx, OR	[co] Transmission	Unattended	13	0.48		

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
140	Oak Hills, near Beaverton, OR	Distribution	Unattended	115	13		56
141	[o] Oregon City - BPA, Wilsonville, OR	Distribution	Unattended	57			
142	Orenco, near Hillsboro, OR	[cp] Transmission	Unattended	115	57	13	280
143	Orenco, near Hillsboro, OR	[cq] Transmission	Unattended	115	13		81
144	Orient, near Gresham, OR	Distribution	Unattended	57	13		28
145	Oswego, Lake Oswego, OR	[cr] Transmission	Unattended	115	13		34
146	Oxford, Salem, OR	[cs] Transmission	Unattended	115	13		50
147	[p] Pearl, BPA, near Wilsonville, OR	Transmission	Unattended	230			
148	[q] Pelton, near Madras , OR	Transmission	Unattended	230	13		120
149	[r] Pelton, near Madras, OR	Transmission	Unattended	13	13		3
150	Peninsula Park, Portland, OR	Distribution	Unattended	115	13		28
151	Pleasant Valley, near Portland, OR	[ct] Transmission	Unattended	115	13		56
152	Port Westward, near Clatskanie, OR	Transmission	Unattended	230	18		900
153	Port Westward, near Clatskanie, OR	Transmission	Unattended	13	4.2		40
154	Portsmouth, Portland, OR	[cu] Transmission	Unattended	115	13		28
155	Progress, near Tigard, OR	[cv] Transmission	Unattended	115	13		50
156	Raleigh Hills, near Portland, OR	Distribution	Unattended	115	13		28
157	Ramapo, near Portland, OR	Distribution	Unattended	115	13		28
158	Redland, near Oregon City, OR	Distribution	Unattended	115	13		22
159	Reedville, near Beaverton, OR	[cw] Transmission	Unattended	115	13		84
160	[s] Rhododendron Switching, OR	Distribution	Unattended	57			
161	River Mill, near Estacada, OR	[cx] Transmission	Unattended	57	11		32
162	Rivergate North Yard, Portland, OR	[cy] Transmission	Unattended	230	115	13	520
163	Rivergate South Yard, Portland, OR	[cz] Transmission	Unattended	115	13		22
164	Rivergate South Yard, Portland, OR	[da] Transmission	Unattended	115	11		22
165	Riverview, Portland, OR	Distribution	Unattended	115	13		28

SUBSTATIONS

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
166	Rock Creek, near Portland, OR	[db] Transmission	Unattended	115	113		28
167	Rockwood, near Gresham, OR	Distribution	Unattended	115	13		78
168	Rosemont, near Lake Oswego, OR	[dc] Transmission	Unattended	115	13		28
169	Roseway, Hillsboro, OR	Distribution	Unattended	115	13		56
170	[t] Round Butte, near Madras, OR	[dd] Transmission	Unattended	500	230	12	561
171	[u] Round Butte, near Madras, OR	[de] Transmission	Unattended	230	13		394
172	Ruby, Gresham, OR	[df] Transmission	Unattended	115	13		28
173	Salem-PGE, near Salem, OR	Distribution	Unattended	57	13		45
174	[v] Sand Springs, South of Bend, OR	Transmission	Unattended	500			
175	Sandy, Sandy, OR	Distribution	Unattended	57	13		28
176	[w] Scappoose, Scappoose, OR	[dg] Transmission	Unattended	115			
177	Scholls Ferry, Beaverton, OR	[dh] Transmission	Unattended	115	13		28
178	Scoggins, near Gaston, OR	Distribution	Unattended	57	13		13
179	Sellwood, Portland, OR	[di] Transmission	Unattended	115	57	13	140
180	Sellwood, Portland, OR	[dj] Transmission	Unattended	115	13		28
181	Sheridan, Sheridan, OR	Distribution	Unattended	57	13		17
182	Sherwood, near Six Corners, OR	Transmission	Unattended	230	115	13	640
183	Shute, Hillsboro, OR	[dk] Transmission	Unattended	115	34.5		100
184	Silverton, Silverton, OR	Distribution	Unattended	57	13		42
185	Six Corners, Six Corners, OR	[dl] Transmission	Unattended	115	13		49
186	[x] Slatt, BPA, Arlington, OR	Transmission	Unattended	500			
187	Springbrook, Newberg, OR	[dm] Transmission	Unattended	115	13		56
188	[y] St. Helens, near St. Helens, OR	[dn] Transmission	Unattended	115			
189	[z] St. Johns-BPA, near Portland, OR	Distribution	Unattended		11		
190	St. Louis, Gervais, OR	Distribution	Unattended	57	13		24
191	St. Marys, East Yard, Beaverton, OR	[do] Transmission	Unattended	115	13		56
192	St. Marys, West Yard, Beaverton, OR	[dp] Transmission	Unattended	230	115	13	960

SUBSTATIONS							
		Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	
Line No.	Name and Location of Substation (a)	Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
193	Sullivan, West Linn, OR	[dq] Transmission	Unattended	57	4.15		33
194	Sullivan, West Linn, OR	[dr] Transmission	Unattended	115	13		45
195	Summit, Government Camp, OR	Distribution	Unattended	57	13		8
196	Summit, Government Camp, OR	Distribution	Unattended	24	13		14
197	Sunset, near Hillsboro, OR	[ds] Transmission	Unattended	115	13		400
198	Sunset, near Hillsboro, OR	[dt] Transmission	Unattended	115	34.5		375
199	Swan Island, Portland, OR	Distribution	Unattended	115	13		53
200	[aa] Sycan, 27 mi S of Silver Lake, OR	Transmission	Unattended	500			
201	Sylvan, near Portland, OR	Distribution	Unattended	115	13		22
202	[ab] Tabor, Portland, OR	[du] Transmission	Unattended	57			
203	Tabor, Portland, OR	[dv] Transmission	Unattended	115	13		22
204	Tektronix, Beaverton, OR	[dw] Transmission	Unattended	115	13		84
205	Tigard, Tigard, OR	Distribution	Unattended	115	13		45
206	Town Center, Portland, OR	[dx] Transmission	Unattended	115	13		56
207	Trojan, near Rainier, OR	[dy] Transmission	Unattended	230	13		56
208	[ac] Troutdale, BPA near Troutdale OR	Transmission	Unattended	230			
209	Tualatin, Tualitin, OR	[dz] Transmission	Unattended	115	13		56
210	Tucannon Mullan Switchyard, Tucannon Dayton, Wa	Transmission	Unattended	230	34.5	13	320
211	Twilight, Canby, OR	Distribution	Unattended	57	13		28
212	University, Salem, OR	[ea] Transmission	Unattended	115	13		22
213	Urban, Portland, OR	[eb] Transmission	Unattended	115	13		112
214	Wacker, Portland, OR	[ec] Transmission	Unattended	115	13	11	56
215	Waconda, near Hopmere, OR	Distribution	Unattended	57	13		41
216	Wallace, Salem, OR	Distribution	Unattended	57	13		28
217	Welches, near Welches, OR	Distribution	Unattended	57	24		10
218	Welches, near Welches, OR	Distribution	Unattended	57	13		18
219	[ad] West Portland, Lower Yard, Tigard, OR	[ed] Transmission	Unattended	115			

SUBSTATIONS							
		Character of Substation	Character of Substation	VOLTAGE (In MVa)	VOLTAGE (In MVa)	VOLTAGE (In MVa)	
Line No.	Name and Location of Substation (a)	Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)
220	West Portland, Upper Yard, Tigard, OR	(ee) Transmission	Unattended	115	13		56
221	West Union, near Hillsboro, OR	(ef) Transmission	Unattended	115	13		56
222	Willamina, near Willamina, OR	Distribution	Unattended	57	13		31
223	Willbridge, Portland, OR	Distribution	Unattended	115	11		28
224	Wilsonville, near Wilsonville, OR	(eg) Transmission	Unattended	115	13		84
225	Woodburn, Woodburn, OR	Distribution	Unattended	57	13		42
226	Yamhill, near Yamhill, OR	Distribution	Unattended	57	13		15
227	Distribution Substations			7,306	1,421	104	2,827.8
228	Distribution Substations Unattended			7,306	1,421	104	2,827.8
229	Transmission Substations			23,647	3,969.5300	326.6800	18,315
230	Transmission Substations Unattended			23,647	3,969.5300	326.6800	18,315
231	Total						21,142.8

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
1	9		Capacitor Banks	3	15.6
2	2		Capacitor Banks	4	12
3	2		Capacitor Banks	2	6
4	2				
5	2		Capacitor Banks	2	7.2
6					
7	1		Capacitor Banks	2	3
8	2		Capacitor Banks	2	6
9	4				
10	1				
11	2		Capacitor Banks	4	12
12	3		Capacitor Banks	4	12
13	2		Capacitor Banks	5	15
14	2				
15	1				
16	1		Capacitor Banks	2	6
17	3				
18	2				
19	2		Capacitor Banks	2	6
20	2		Capacitor Banks	2	7.2
21	2		Capacitor Banks	1	12.15
22	3				
23	1		Capacitor Banks	2	6
24					
25	2		Capacitor Banks	2	48
26	4				
27	6	2			
28	4		Capacitor Banks	8	28.8
29					
30	2				
31	1				
32	2				
33	2		Capacitor Banks	4	12
34	2		Capacitor Banks	4	12
35	2		Capacitor Banks	4	13.2
36	2		Capacitor Banks	4	12
37					
38					

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
39	2		Capacitor Banks	4	13.2
40	1		Capacitor Banks	2	6
41	1		Capacitor Banks	2	6
42	3				
43	2				
44	1		Capacitor Banks	2	6
45	1				
46	1		Capacitor Banks	2	6
47	3				
48	1				
49	1		Capacitor Banks	2	6
50	2		Capacitor Banks	4	6
51	1				
52	1				
53	2		Capacitor Banks	2	6
54	1		Capacitor Banks	3	9
55	1		Capacitor Banks	2	3
56	2		Capacitor Banks	4	12.6
57	5		Capacitor Banks	4	28.8
58	4		Capacitor Banks	2	32.4
59	1				
60	1				
61	2		Capacitor Banks	4	12
62	2		Capacitor Banks	2	3.6
63	1		Capacitor Banks	1	3.6
64	2		Capacitor Banks	1	3
65	1				
66	1				
67	2				
68					
69			Series Capacitor	1	363
70	1				
71	1		Capacitor Banks	2	6
72	1		Capacitor Banks	2	6
73	2		Capacitor Banks	4	12
74	2		Capacitor Banks	4	12
75	1	1			
76	1		Capacitor Banks	2	3

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
77					
78	2				
79					
80	3		Capacitor Banks	5	36
81	2		Capacitor Banks	4	12
82	1		Capacitor Banks	2	6
83	2		Capacitor Banks	4	12
84	2		Capacitor Banks	4	18
85	1		Capacitor Banks	2	6
86	1		Capacitor Banks	2	6
87	2		Capacitor Banks	4	14.4
88	2		Capacitor Banks	4	12
89	3				
90	2		Capacitor Banks	4	12
91	2		Capacitor Banks	2	7.2
92	3				
93	2		Capacitor Banks	2	6
94	2		Capacitor Banks	3	10.8
95	2		Capacitor Banks	4	12
96	2				
97					
98	2		Capacitor Banks	4	12
99	2		Capacitor Banks	2	6
100	2		Capacitor Banks	4	12
101	1		Capacitor Banks	2	6
102	1				
103	2				
104	2		Capacitor Banks	3	10.2
105	3		Capacitor Banks	6	20.4
106			Reactors	3	180
107	1		Capacitor Banks	2	6
108	5		Capacitor Banks	10	54
109	3				
110	3		Capacitor Banks	6	18
111	2				
112	3		Capacitor Banks	6	18.6
113	2		Capacitor Banks	4	12
114	2		Capacitor Banks	1	3.6

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
115	1		Capacitor Banks	2	6
116	1	1			
117	1	1			
118	1	1			
119	1	1			
120	1	1			
121	1	1			
122	1	1			
123	1	1			
124	2		Capacitor Banks	4	9
125	1				
126	1		Capacitor Banks	3	15
127	2		Capacitor Banks		
128	2		Capacitor Banks	3	9.6
129	2		Capacitor Banks	3	10.8
130	1				
131	2		Capacitor Banks	4	12
132	3				
133	3		Capacitor Banks	3	15
134	1		Capacitor Banks	4	18
135	2				
136	1				
137	2				
138					
139					
140	2		Capacitor Banks	4	14.4
141					
142	2				
143	3		Capacitor Banks	6	18
144	1		Capacitor Banks	2	6
145	2		Capacitor Banks	2	7.2
146	2		Capacitor Banks	4	12.3
147					
148	3				
149	1				
150	1		Capacitor Banks	2	6
151	2		Capacitor Banks	4	12
152	3				

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
153	2				
154	1				
155	2		Capacitor Banks	4	13.8
156	1		Capacitor Banks	2	6.6
157	1		Capacitor Banks	2	6
158	1				
159	3		Capacitor Banks	6	18
160					
161	2				
162	4	1	Capacitor Banks	1	24
163	1		Capacitor Banks	2	7.2
164	1		Capacitor Banks	2	6.716
165	1		Capacitor Banks	2	6
166	1		Capacitor Banks	2	6
167	3		Capacitor Banks	5	15
168	1		Capacitor Banks	2	6
169	2		Capacitor Banks	4	12
170	3		Reactors	12	180
171	4				
172	1		Capacitor Banks	2	6
173	2		Capacitor Banks	4	12
174			Series Capacitor	1	546
175	1		Capacitor Banks	2	6
176					
177	1		Capacitor Banks	2	6
178	2		Capacitor Banks	1	10.8
179	1		Capacitor Banks	1	24
180	1		Capacitor Banks	2	6
181	1		Capacitor Banks	3	15.6
182	2				
183	2		Capacitor Banks	4	18
184	2				
185	2		Capacitor Banks	2	6
186					
187	2		Capacitor Banks	5	36
188			Capacitor Banks	1	24
189					
190	2		Capacitor Banks	2	7.2

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
191	2		Capacitor Banks	4	12
192	3		Capacitor Banks	3	108
193	1				
194	2		Capacitor Banks	4	12
195	1				
196	1				
197	8		Capacitor Banks	25	150
198	3				
199	2		Capacitor Banks	4	12
200			Series Capacitor	1	546
201	1		Capacitor Banks	2	6
202					
203	1		Capacitor Banks	2	6
204	3		Capacitor Banks	6	18
205	2		Capacitor Banks	4	12
206	2		Capacitor Banks	2	6
207	2				
208					
209	2		Capacitor Banks	4	13.2
210	2		Capacitors/reactors	6	90
211	1	1	Capacitor Banks	3	19.2
212	1		Capacitor Banks	2	7.2
213	4		Capacitor Banks	5	15.6
214	2		Capacitor Banks	2	6
215	2		Capacitor Banks	2	6
216	1		Capacitor Banks	2	6
217	1	1	Capacitor Banks	1	12
218	2		Capacitor Banks	2	6
219			Capacitor Banks	1	24
220	2		Capacitor Banks	4	13.2
221	2		Capacitor Banks	4	12
222	2		Capacitor Banks	2	7.8
223	1				
224	3		Capacitor Banks	6	18
225	2		Capacitor Banks	4	13.2
226	2		Capacitor Banks	1	1.8
227	140	10		167	576.15
228	140	10		167	576.15

SUBSTATIONS					
Line No.	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Conversion Apparatus and Special Equipment Number of Units (j)	Conversion Apparatus and Special Equipment Total Capacity (In MVa) (k)
229	248	4		289	3,131.8160
230	248	4		289	3,131.8160
231					

Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(b) Concept: SubstationNameAndLocation
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 16% share of the jointly owned capacity. 100% of thecapacity is reported.
(c) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(d) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of constructionmade to BPA recorded to FERC account 353.
(e) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(f) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(g) Concept: SubstationNameAndLocation
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of jointly owned capacity. 100% of the capacity is reported.
(h) Concept: SubstationNameAndLocation
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 14% share of the jointly owned capacity. 100% of thecapacity is reported.
(i) Concept: SubstationNameAndLocation
Contribution in aid of construction made to Bonneville Power Administration in 1995 and 2006 to FERC account 353.
(j) Concept: SubstationNameAndLocation
Switching only. Identified location is Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(k) Concept: SubstationNameAndLocation
Line compensation only.
(l) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(m) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA, recorded to FERC account 353.
(n) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to Boneville Power Administration recorded to FERC account 353.
(o) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(p) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(q) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.
(r) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.
(s) Concept: SubstationNameAndLocation
Switching only.
(t) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 76% share of the jointly owned capacity. 100% of the capacity is reported.
(u) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 76% share of the jointly owned capacity. 100% of the capacity is reported.
(v) Concept: SubstationNameAndLocation
Line compensation only.
(w) Concept: SubstationNameAndLocation
Switching only. Distribution owned by Columbia River PUD.

(x) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(y) Concept: SubstationNameAndLocation
Switching only. Distribution owned by Columbia River PUD.
(z) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(aa) Concept: SubstationNameAndLocation
Line compensation only.
(ab) Concept: SubstationNameAndLocation
Switching only
(ac) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(ad) Concept: SubstationNameAndLocation
Switching only
(ae) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
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Name of Respondent: Portland General Electric Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/25/2022	Year/Period of Report End of: 2021/ Q4

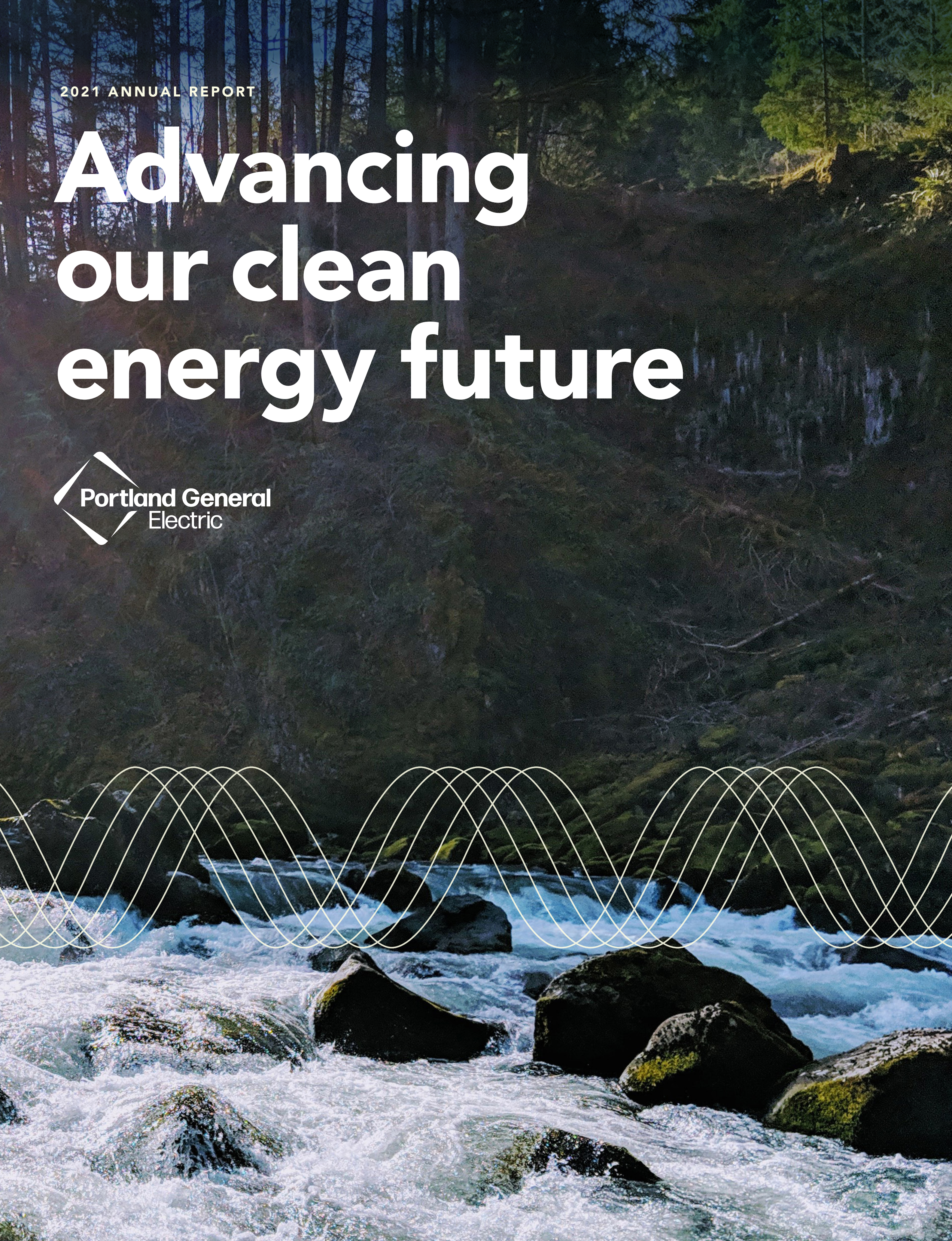
TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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 OPUC Order No. 18-823	121 SW Salmon Street Corp	418	8,295,137
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative Services	121 SW Salmon Street Corp	146	1,440,246
22	Administrative Services	Salmon Springs Hospitality Group	146	507,569
42				

2021 ANNUAL REPORT

Advancing our clean energy future

Portland General Electric



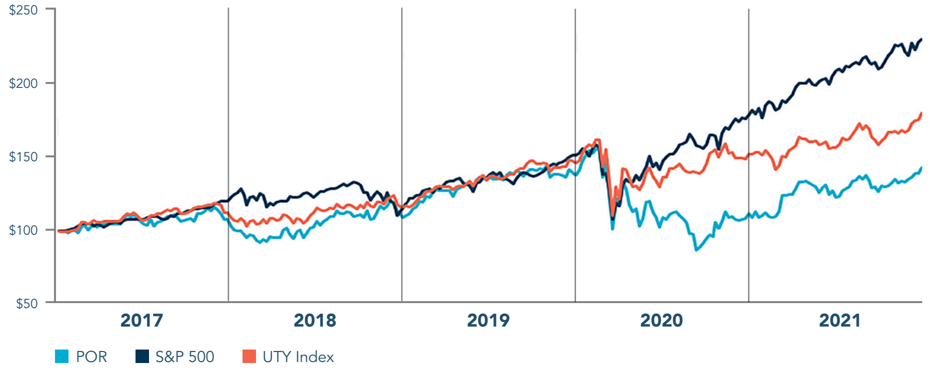
Financial Highlights

About Portland General Electric

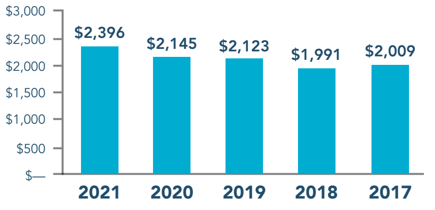
Portland General Electric Company, headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 900,000 retail customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

Dollars in millions, except per-share amounts	2021	2020	2019	2018	2017
Total revenues	$2,396	$2,145	$2,123	$1,991	$2,009
Income from operations	$378	$269	$353	$346	$380
Net income	$244	$155	$214	$212	$187
Earnings per share, diluted	$2.72	$1.72	$2.39	$2.37	$2.10
Return on average equity	9.2%	6.0%	8.4%	8.6%	7.9%
Total assets	$9,494	$9,069	$8,394	$8,110	$7,838
Dividends paid per common share	$1.68	$1.56	$1.50	$1.41	$1.32
Weighted-average shares outstanding (in thousands), diluted	89,627	89,645	89,559	89,347	89,176
Average number of customers throughout the year	912,000	902,000	890,000	882,000	870,000
Common equity ratio[(1)]	45.2%	45.0%	49.9%	50.3%	49.9%
Senior secured debt ratings (S&P/Moody's)	A/A1	A/A1	A/A1	A/A1	A-/A1
Employees	2,839	2,870	2,949	2,967	2,906

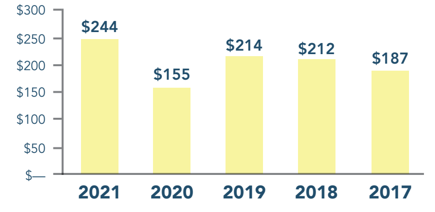
Stock Performance[(2)]



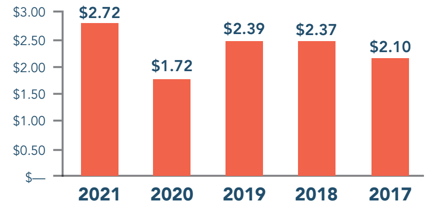
Total Revenue (dollars in millions)



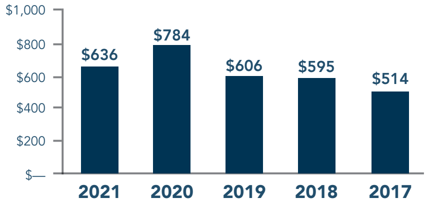
Net Income (dollars in millions)



Diluted Earnings per Share



Capital Expenditures (dollars in millions)



(1) Excludes lease obligations

(2) The chart above assumes a $100 investment in Portland General Electric's common stock and each index on Dec. 31, 2016, and that all dividends were reinvested

Letter from our Chief Executive Officer

MARIA M. POPE
President & Chief Executive Officer

To our shareholders

2021 was a year of strong growth and execution to advance our clean energy strategy. Against the backdrop of the ongoing pandemic, the historic ice storm and record heat, we focused on investments and new technologies to improve reliability and resiliency.

As extreme weather impacted our region and customers once again, we focused on improving storm response. During the February ice storm, we restored 759 thousand customer outages. During the hottest day of the June heat wave, we served a record load of 4,447 MWs. Most importantly, with each crisis we improved our operating performance.

Opening the new Integrated Operations Center and launching the Advanced Distribution Management System in December were key milestones. These investments embody our vision and strategy and establish the foundation for an intelligent energy network that enables the integration of greater amounts of renewable energy and increases system flexibility and resiliency. Together, these advancements expand opportunities to partner with consumers to grow distributed energy programs and accelerate the expansion of flexible load programs. They are also key to accelerating our customers' and partners' clean energy transformation by leveraging the scale and diversity of West-wide generation and transmission assets, and intelligently connecting systems across the Western power grid.

Enhancing our digital capabilities across the enterprise to improve performance and deliver exceptional customer experiences was and will remain a key focus. We simplified our work and reduced costs by equipping field crews with new digital tools, upgrading supply chain systems, and increasing call center performance. Through advanced data analytics and smart grid technologies, we are increasing reliability even under uncertain and extreme weather conditions.

Our path to decarbonization was further catalyzed by Oregon's clean energy legislation in 2021. We worked with a broad coalition of stakeholders and the Oregon Legislature to set some of the most ambitious clean electricity targets in the country – achieving at least an 80% reduction in greenhouse gas emissions associated with the power served to customers by 2030 and a 100% reduction by 2040. PGE was the first utility in the country to sign the Climate Pledge, committing to achieving net zero emissions across all of our company operations by 2040, including our fleet and facilities. And for the thirteenth consecutive

2021 net income was **$244 million,** or **$2.72** per diluted share. Our share price rose by **23.7%** in comparison to the industry average of **14.6%**

year, our voluntary renewable energy program was ranked #1 in the U.S. by the National Renewable Energy Laboratory.

We continued our long-standing commitment to diversity, equity and inclusion and increased the representation of Black, Indigenous and People of Color as well as women in leadership and across our company. We achieved a perfect score for the ninth year in a row on the Human Rights Campaign Foundation's Corporate Equality Index, and, for a fourth year running, PGE was included in the Bloomberg Gender-Equality Index.

2021 net income was $244 million, or $2.72 per diluted share. Our share price rose by 23.7% in comparison to the industry average of 14.6%. We invested over $600 million in our system to upgrade and replace generation, transmission and distribution assets. We raised $400 million in long-term debt at very attractive interest rates, including $150 million of our first-ever green bonds.

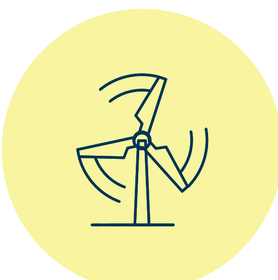
As we look to the future, we have robust economic growth and expect load growth of approximately 1.5%, largely from higher commercial and industrial demand. Ongoing focus on cost management and operational excellence will help mitigate inflationary cost pressures and volatile energy markets. We are on track to achieve 4 to 6% long-term EPS growth target and 5 to 7% long-term dividend growth target. Full-year earnings guidance for 2022 is $2.75 to $2.90 per diluted share.

I am humbled by the opportunities and challenges ahead of us. Thanks to the expertise and dedication of our nearly 3,000 employees, as well as our customers and community leaders, we are well prepared to power the advancement of society, creating a stronger, sustainable and more resilient future for Oregon.

Maria M. Pope
President and CEO

Powering the Advancement of Society

Our mission is to power the advancement of society and deliver a smarter, cleaner future for Oregon. Together with our customers, communities, and partners, we are creating a safe, reliable, clean energy future. We aim to lead the energy transformation by decarbonizing the grid, electrifying the economy from transportation to homes and buildings, and in operating our business to remain cost effective and financially healthy. Executing on our Decarbonize, Electrify and Perform strategy requires a focus and commitment to affordability, grid reliability and equitable outcomes for all customers like never before in our 130-year history.



Decarbonize

#1

In voluntary renewable energy

For the thirteenth consecutive year, our voluntary renewable energy program was ranked #1 in the U.S. by the National Renewable Energy Laboratory

ZERO

Getting to zero

Worked closely with partners to help establish Oregon's clean energy legislation aimed at achieving at least an 80% reduction in greenhouse gas (GHG) emissions from power served to customers by 2030 and **100%** reduction by 2040

Integrated Operations Center

Intelligent energy

Opened the new Integrated Operations Center and launched the Advanced Distribution Management System establishing the foundation for an intelligent energy network that enables the integration of greater amounts of renewable energy and increases system flexibility and resiliency

Electrify

Electrification grants

PGE's Drive Change Fund awarded **$2.25M** to 11 organizations throughout Oregon to help make electric vehicle adoption more accessible

Energy equity

Worked with the Governor's Office, legislators and a coalition of other stakeholders to craft and support legislation to expand access to electric vehicles and charging infrastructure, particularly to people with low incomes and people of color

375-500MW

Of renewables to be added

Issued our inaugural Distribution System Plan and an RFP to add 375 to 500 MW of renewables and **375 MW** of non-emitting capacity

Electric Island

Daimler Truck North America (DTNA) and PGE opened the first-of-its-kind heavy-duty electric truck charging site, known as Electric Island

Perform

$150M

Placed in green bonds

Established a Green Financing Framework and placed $150 million in green bonds as part of a **$400** million long-term debt issuance

Improved storm response

During the February ice storm, we restored **759,159** customer outages. During the hottest day of the June heat wave, we served a record load of **4,447 MWs**

$600M

Invested in the future

Invested over $600 million to upgrade and replace generation, transmission and distribution assets

Growing strong

Healthy customer growth of approximately **1%** and weather-adjusted loads increased **4%**

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

FORM 10-K

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

For the fiscal year ended December 31, 2021

OR

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

For the Transition period from ______ to ______

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

As of June 30, 2021, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $4,106,085,794. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 7, 2022, there were 89,426,860 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on April 22, 2022.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2021

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DEFINITIONS

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

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

PART I

ITEM 1. BUSINESS.

General

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

PGE's state-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2021, the Company added nine thousand customers, and as of December 31, 2021, served a total of 917 thousand retail customers.

Available Information

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

Regulation

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

Federal Regulation

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

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

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA).

The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGE's BAA does not have a material impact on the Company.

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

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

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

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

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

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

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

State of Oregon Regulation

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

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

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Company's debt-to-equity capital structure, return on equity, overall rate of return, and customer prices.
- *Annual Power Cost Updates*. The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Company's net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's consolidated statements of income) and is net of wholesale revenues, which are classified in the consolidated statements of income as Revenues, net. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC.
- *Renewable Energy.* The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS.
    - In 2016, the State also passed a law referred to as the Oregon Clean Electricity and Coal Transition Plan (SB 1547), which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers' energy supply. For further information on SB 1547, see "*RPS Standards and Other Laws"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
    - During 2021, the State legislature passed House Bill (HB) 2021, which establishes clean energy targets and sets out a framework for PGE and other investor-owned utilities and electric service suppliers in the state. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For further information on HB 2021 and the baseline to which the target reductions apply, see "*House Bill 2021"* in the Environmental Laws and Regulations portion of the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Regulatory Accounting

PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

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

Customers and Revenues

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

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 8% of PGE's total retail revenues or 13% of total retail deliveries.

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

	Years Ended December 31,					
	2021		2020		2019	
Retail revenues [(1)] (dollars in millions):						
Residential	$ 1,118	54 %	$ 1,030	53 %	$ 981	52 %
Commercial	708	34	634	33	654	35
Industrial	279	13	246	13	222	12
Subtotal	2,105	101	1,910	99	1,857	99
Alternative revenue programs, net of amortization	(29)	(1)	(6)	—	2	—
Other accrued revenues, net [(2)]	2	—	28	1	22	1
Total retail revenues	$ 2,078	100 %	$ 1,932	100 %	$ 1,881	100 %
Retail energy deliveries [(3)] (MWh in thousands):						
Residential	7,978	39 %	7,756	40 %	7,471	38 %
Commercial	7,193	35	6,855	35	7,318	38
Industrial	5,361	26	4,932	25	4,671	24
Total retail energy deliveries	20,532	100 %	19,543	100 %	19,460	100 %
Average number of retail customers:						
Residential	800,372	88 %	791,119	88 %	779,673	88 %
Commercial	111,569	12	110,851	12	110,084	12
Industrial	268	—	267	—	262	—
Total	912,209	100 %	902,237	100 %	890,019	100 %

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

(2) Amounts for the years ended December 31, 2020 and 2019 are primarily comprised of $24 million and $23 million, respectively, of amortization, including interest, related to the $45 million deferral recorded in 2018 for the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA).

(3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

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

	Years Ended December 31,		
	2021	2020	2019
Residential			
Revenue per customer (in dollars):	$ 1,320	$ 1,226	$ 1,177
Usage per customer (in kilowatt hours):	9,968	9,804	9,582
Revenue per kilowatt hour (in cents):	13.24 ¢	12.50 ¢	12.28 ¢
Commercial			
Revenue per customer (in dollars):	$ 6,303	$ 5,684	$ 5,901
Usage per customer (in kilowatt hours):	64,478	61,837	66,481
Revenue per kilowatt hour (in cents):	9.78 ¢	9.19 ¢	8.88 ¢
Industrial			
Revenue per customer (in dollars):	$ 1,044,314	$ 921,540	$ 847,079
Usage per customer (in kilowatt hours):	20,002,246	18,472,161	17,827,115
Revenue per kilowatt hour (in cents):	5.22 ¢	4.99 ¢	4.75 ¢

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

In addition to standard cost of service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options. For additional information on customer options, see "*Customer Choice Programs*" within this Customers and Revenues section of this Item 1.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season. Increased use of air conditioning in PGE's service territory has caused the summer peaks to increase over time, while the historical winter peak has not increased in over 20 years. In recent years, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. Economic conditions can also affect residential demand as job growth and population growth in PGE's service territory have led to increased customer growth rates. The COVID-19 pandemic has introduced additional behavioral patterns as residential customers spend more time at home. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see *"General Rate Case"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

Customer Choice Programs—Under cost of service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing.

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

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

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

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

PGE's customers are committed to purchasing clean energy, as over 235 thousand residential and small commercial customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. Oregon's most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area have set, or are considering, similar goals.

In response, the Company implemented a new customer service option, the Green Future Impact Program, which allows for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in 2019, the program provides business customers access to bundled renewable attributes from those resources. On March 29, 2021, the OPUC issued an order that expanded the program by 200 MW and provided for the possibility of PGE ownership of the underlying renewable resources under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable integrated power while providing customer choice and a cleaner energy system. In December 2021, the OPUC issued an order, which approved a petition to increase capacity under the customer-provided renewable resources by 250 MW, which would bring the total available capacity under the program to 750 MW. For more information on the Company's power purchase agreements that currently serve the Green Future Impact Program, see *"Green Future Impact Program"* within Purchased Power in the Power Supply section of this Item 1.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand, depending upon the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. PGE also participates in the California Independent System Operator's western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 11% of total revenues in 2021 and 8% in both 2020 and 2019.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 3% of total revenues in 2021, 2% in 2020, and 3% in 2019.

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial customers, is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity.

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

	Heating Degree-Days	Cooling Degree-Days
2021	3,828	838
2020	3,836	600
2019	4,165	564
15-year average	4,120	550

In June 2021, PGE set a new all-time high net system load peak of 4,447 megawatts (MW), surpassing the previous all-time peak that occurred in December 1998 by over 9%. The Company's previous summer peak of 3,976 MW occurred in August 2017. The following table presents PGE's average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As the table below illustrates, although the average winter loads continue to run higher than average summer loads, the Company continues to experience its highest annual peak loads during the summer months:

	Winter Loads			Summer Loads		
	Average	Peak	Month	Average	Peak	Month
2021	2,657	3,619	December	2,487	4,447	June
2020	2,566	3,367	December	2,289	3,771	July
2019	2,609	3,422	February	2,263	3,765	June

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

Power Supply

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

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

	As of December 31,			
	2021		2020	
	Capacity	%	Capacity	%
Generation:				
Thermal [1]:				
Natural gas	1,842	35 %	1,831	34 %
Coal	296	5	296	6
Total thermal	2,138	40	2,127	40
Wind [2]	817	16	817	16
Hydro [3]	495	9	495	9
Total generation	3,450	65	3,439	65
Purchased power:				
Long-term contracts:				
Hydro [3]	803	15	512	10
PURPA qualifying facilities [4]	298	6	279	5
Dispatchable standby generation	130	2	123	2
Capacity	100	2	100	2
Wind [2]	300	6	300	6
Solar	7	—	7	—
Biomass	10	—	10	—
Total long-term contracts	1,648	31	1,331	25
Short-term contracts	216	4	538	10
Total purchased power	1,864	35	1,869	35
Total resource capacity	5,314	100 %	5,308	100 %

(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant.
(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions.
(3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%, dependent upon river flows.
(4) Capacity represents contracted capacity for power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act of 1978 (PURPA).

For information regarding actual generating output and purchases for the years ended December 31, 2021 and 2020, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

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

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

The Company operated, and continues to have a 90% ownership interest in the Boardman coal-fired generating plant (Boardman), which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the state of Oregon, see *"RPS Standards and Other Laws"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW. During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it now owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a capacity of 200 MWs through power purchase agreements. For additional information on Wheatridge, see *"The Resource Planning Process"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGE's ownership interest in the project is now 50.01%. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, CTWS's ownership percentage would exceed 50%. PGE purchases 100% of the CTWS's share of the project output. For more information see *"CTWS"* within Purchased Power in the Power Supply section of this Item 1.

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

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

PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants.

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

To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada.

Coal The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits.

Purchased Power

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

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

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

Hydro—During 2021, the Company had the following agreements:

- *Public Utility Districts*—PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 404 MW of capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time:
    - 165 MW of capacity with Grant County PUD that expires in 2052;
    - 139 MW of capacity with Douglas County PUD that expires in 2028; and
    - 100 MW of capacity with Douglas County PUD that expires in 2025.
- *CTWS*—PGE has a long-term agreement under which the Company purchases CTWS' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 162 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE pays fixed capacity and energy charges to CTWS for 100% of its share of the project through 2024. On June 30, 2021 the CTWS notified PGE of their intent to exercise their option to purchase an additional undivided 16.66%

ownership interest in Pelton/Round Butte and closed on the purchase on January 1, 2022. As a result of the sale, capacity from company-owned generation will decrease by approximately 76 MW, and capacity from purchased power will increase by a corresponding amount. Under the PPA, PGE will purchase 100% of the CTWS's additional share of the project and payments under the PPA will increase proportionately. In the fourth quarter of 2021, PGE and CTWS executed an additional 16-year PPA which begins on January 1, 2025, that effectively extends the term from 2024 to 2040 and increases the capacity payments in the extension period.

- *Other*—The remaining capacity is primarily comprised of two additional contracts that provide for the purchase of power generated from hydroelectric projects with capacity of 236 MW in total:
    - 200 MW of capacity with Bonneville Power Administration that expires in 2024; and
    - 36 MW of capacity with Portland Hydro that expires in 2032

PURPA qualifying facilities—PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of energy. As of December 31, 2021, PGE had contracts with 67 on-line QFs, providing a total of 298 MW of capacity. As of December 31, 2021, PGE has nine contracts with QFs representing 70 MW of capacity that are not yet operational, of which one of the QF PPAs is in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years, measured from the date of execution.

The expense and volume of purchases from QFs for the years ended December 31, 2021 and 2020 were as follows:

	2021	2020
PURPA contract expense (in millions)	$ 55	$ 43
MWh purchased under PURPA contracts (in thousands)	683	498
Average cost per MWh from PURPA contracts	$ 79.89	$ 85.31

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

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned backup generators when needed to provide NERC-required operating reserves. As of December 31, 2021, there were 60 customer-owned sites with a total DSG capacity of 130 MW. PGE continues to pursue expansion of the program with the goal of having an additional 3 to 10 MW of customer-owned DSG projects online by the end of 2022.

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

Wind—PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2050. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions.

Solar—PGE has three contracts representing seven MW of capacity to purchase power generated from photovoltaic solar projects that extend to 2036 and 2037. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions. Construction on the solar and battery components of Wheatridge, which will supply the Company with an additional 50 MW and 30 MW of capacity, respectively, is ongoing and expected to be completed in early 2022. This additional solar and battery capacity is not reflected in the table above. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and will sell their portion of the output to PGE.

Biomass—PGE has one contract to purchase biomass energy that is set to expire in 2022.

Green Future Impact Program— PGE has two contracts representing 300 MW of capacity to purchase power generated from renewable resources to support the Green Future Impact Program:

- a 15-year contract with Avangrid Renewables representing 162 MW from a renewable energy facility in Gilliam County, Oregon that is expected to be placed in service in May 2022. This additional capacity is not reflected in the table above; and
- a 15-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2022. This additional capacity is not reflected in the table above.

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

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

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

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

Future Energy Resource Strategy

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

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2021, PGE delivered approximately 26 million megawatt hours (MWh) through 1,274 circuit miles of transmission lines operating at or above 115 kilovolts (kV).

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Company's generation to serve its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency.

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

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

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

Environmental Matters

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

Air Quality

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

Climate Change—In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP.

In 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, to repeal and replace the CPP and, in 2019, finalized the ACE rule, which established guidelines for states to develop plans to address GHG emissions from existing coal-fired plants, such as Colstrip in the case of PGE. With the finalization of the ACE rule, the CPP was repealed. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA. Notwithstanding objections from the Biden administration that the EPA intended to issue a new rule that takes recent changes in the electricity sector into account, on October 29, 2021, the U.S. Supreme Court agreed to hear an appeal of the D.C. Circuit decision. Oral argument in the case is scheduled for February 28, 2022 with a decision expected during the summer of 2022.

PGE will assess the Supreme Court's decision, as well as the EPA's response, for impacts on Colstrip and the Company's existing natural gas fleet.

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

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

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification or permit from the state in which the activity will occur. In Oregon, Montana, and Washington, the Departments of Environmental Quality and Department of Ecology are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits or certificates of compliance for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards.

Threatened and Endangered Species and Wildlife

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

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

Hazardous Material

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

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

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

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

Human Capital Management

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

Employees and Collective Bargaining Agreements—PGE had 2,839 employees in its workforce as of December 31, 2021, with 678 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). The agreements cover 614 and 64 employees and expire March 2022 and August 2022, respectively. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce.

Competitive Pay and Benefits—PGE is committed to pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees. PGE also has an Employee Assistance Program that provides free and confidential wellness counseling to eligible employees and their families.

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

Health and Safety—PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Company's efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety.

Diversity, Equity, and Inclusion—PGE promotes an inclusive workforce through pay equity practices, racial equity training, and development opportunities for women and people of color to advance into management. Black, Indigenous, and People of Color comprise over 25% of its employees and nearly 23% of management. One third of its employees and over 34% of its management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Company's supplier diversity program ensures opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers.

COVID-19—Since the beginning of the COVID-19 pandemic, PGE has taken steps to protect employees by making changes to work schedules, work locations, cleaning practices, work protocols, and information services—including encouraging employees to take advantage of its comprehensive health, wellness, family, and leave programs. The Company continues to prioritize the health and safety of its employees and be informed by federal, state and local officials to align its efforts with current information.

Information about Our Executive Officers

The following are PGE's current executive officers:

Name	Age	Current Position and Previous Experience	Year Appointed Officer
James A. Ajello	68	Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2021 to present), Senior Advisor (November 2020 to December 2020), Executive Vice President and Chief Financial Officer at Hawaiian Electric Industries (January 2009 to April 2017 - retired), Senior Vice President, Business Development at Reliant Energy (January 2000 to January 2009), Managing Director, UBS Securities (January 1984 to August 1998).	2021
Larry N. Bekkedahl	60	Senior Vice President, Advanced Energy Delivery (July 2021 to present), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at BPA (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012).	2014
Bradley Y. Jenkins	58	Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman (September 2012 to November 2013), Operations Manager, Boardman (March 2012 to September 2012).	2015
Lisa A. Kaner	61	Vice President, General Counsel and Corporate Compliance Officer (July 2017 to present), trial attorney and shareholder at Markowitz Herbold PC (1994 to June 2017).	2017
John T. Kochavatr	48	Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies & Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017).	2018
John C. McFarland	41	Vice President, Chief Customer Officer (April 2019 to present). Director, Global Digital Experience at General Motors (February 2016 to March 2019), Chief Marketing Officer at OnStar (a subsidiary of General Motors, October 2012 to January 2016), Senior Manager of Strategy at General Motors (September 2010 to September 2012), Brand Management and Finance at Procter & Gamble (August 2002 to August 2010).	2019

Anne F. Mersereau	59	Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present), Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011).	2016
Maria M. Pope	56	President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to December 2017), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008).	2009
W. David Robertson	54	Vice President, Public Affairs (August 2009 to present), Director of Government Affairs (June 2004 to August 2009). Director of Government Relations - West for PG&E National Energy Group (June 1998 to June 2004). Senior Associate for Robertson, Grosswiler & Co. (November 1996 to June 1998). Field Representative and Legislative Assistant for U.S. Sen. Mark O. Hatfield (January 1990 to November 1996).	2009
Brett M. Sims	53	Vice President, Strategy, Regulation and Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020), Director of Origination, Structuring & Resource Strategy (May 2001 to September 2017).	2020

ITEM 1A. RISK FACTORS.

When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K. These risk factors could have a material impact on PGE's business, financial condition, results of operations, or cash flows, or that materially adversely affect PGE's actual results and cause such results to differ materially from those expressed in any forward-looking statements made by the Company or on its behalf. PGE may also be harmed by risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial. If any of these risks occur, PGE's business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Company's securities could substantially decline. These risk factors should be read in conjunction with the other information in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC.

REGULATORY, LEGAL, AND COMPLIANCE RISKS

PGE is subject to extensive regulation that affects the Company's operations and costs.

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

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements, and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

PGE attempts to manage its costs at levels consistent with the OPUC approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

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

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

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

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

PGE is subject to various environmental laws, regulations, and other standards including, but not limited to, federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, emissions of greenhouse gases, including, but not limited to, carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of some fuels required for power generation, require additional pollution control equipment, investment in non-emitting resources, and otherwise increase costs, and increase capital expenditures.

There are significant capital, operating and other costs associated with compliance with these laws and regulations, and violations of these laws and regulations could potentially result in significant civil fines, criminal penalties, and other sanctions. There is no assurance that the OPUC will grant PGE complete recovery of such costs, which could have a material adverse effect on the Company's results of operations.

Future laws and regulations could mandate new or additional GHG emissions reductions that could lead to increased capital and operating costs and have an adverse impact on the Company's results of operations.

Future legislation or regulations could result in limitations on GHG emissions from the Company's fossil fuel-fired generation facilities. Compliance with any new or additional GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with non-emitting facilities.

The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: i) the timing of the implementation of emissions reduction rules; ii) required levels of emissions reductions; iii) requirements with respect to the allocation of emissions allowances; iv) the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and v) PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material. There is no assurance that the OPUC will grant PGE complete recovery of such costs, which could have a material adverse effect on the Company's results of operations.

Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

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

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

PGE supplements its own generation with wholesale power purchases to meet its retail load requirement. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by various factors, such as unanticipated delays and cost increases including, but not limited to, supply chain disruption and cost inflation, failure of counterparties to perform under agreements, the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects, or the abandonment of capital projects, all of which could result in the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

ECONOMIC, FINANCIAL, AND MARKET RISKS

Economic conditions that result in reduced demand for electricity and could impair the financial stability of PGE's customers could affect the Company's results of operations.

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

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

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

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

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

Access to capital markets is important to PGE's ability to operate its business and complete its capital projects. Credit rating agencies evaluate the Company's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase fees on PGE's syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

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

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

PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $650 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event certain circumstances occur that could result in a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility.

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

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

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

Market prices for power and natural gas are subject to forces that are often not predictable and that can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.

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

Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

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

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

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

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

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

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

BUSINESS AND OPERATIONAL RISKS

The spread of COVID-19 could have a material adverse effect on PGE's business.

The COVID-19 pandemic has adversely impacted economic activity and conditions worldwide. Measures to control the spread of COVID-19 have affected the demand for the products and services of many businesses in PGE's service territory and disrupted supply chains around the world. Due to COVID-19, PGE has observed an increase in past due accounts and late customer payments resulting in incremental bad debt expense that has been deferred pursuant to the OPUC's COVID-19 deferral. PGE has also observed a change in the trend of customer demand with an increase in residential usage as customers stay at home and a decrease in commercial usage due to COVID-19 related closures or restrictions and economic conditions. Although these trends have not had a material impact on the Company to date, management believes that these trends will continue and the full scope and extent of the impacts of COVID-19 on the Company's operations remains uncertain and depends on multiple variables. PGE continues to monitor the impacts of the COVID-19 pandemic on its workforce, liquidity, capital markets, reliability, cybersecurity, customers, and suppliers, along with overall macroeconomic conditions. Although the Company cannot predict with certainty the full extent of the COVID-19 pandemic's impact on its business, a protracted slowdown of broad sectors of the economy, changes in demand for commodities, or significant changes in legislation or regulatory policy to address the COVID-19 pandemic could ultimately result in a significant reduction in demand for electricity in PGE's service territory, increased late customer payments or uncollectible accounts, and the inability of the Company's contractors, suppliers, and other business partners to fulfill their contractual obligations, any of which could have, or continue to have, a material adverse effect on the Company's results of operations, financial condition and cash flows.

Government imposed COVID-19 vaccine mandates could have a material adverse effect on PGE's business.

On September 9, 2021, President Biden issued an executive order requiring all employers with U.S. government contracts to ensure that their U.S.-based employees, contractors and subcontractors, that work on or in support of U.S. government contracts, are fully vaccinated against COVID-19 as required by the executive order. The executive order includes on-site and remote U.S.-based employees, contractors, and subcontractors and provides for limited medical and religious exceptions.

In addition, on September 9, 2021, President Biden announced that he has directed Occupational Safety and Health Administration (OSHA) to develop an Emergency Temporary Standard (ETS) mandating either the full vaccination against COVID-19 or weekly testing of employees for employers with 100 or more employees. The executive order was challenged in the courts, and on January 13, 2022, the United States Supreme Court held that OSHA's ETS exceeded its authority, and issued a stay on enforcement of the ETS mandate for large private employers. On January 25, 2022, OSHA issued an announcement it would withdraw the vaccination and testing ETS that was issued on November 5, 2021.

Although the ETS mandate was withdrawn by OSHA, it is currently not possible to predict with certainty the impact future potential mandates will have on PGE's workforce. Additional vaccine mandates may be announced in jurisdictions in which the Company operates. PGE's implementation of these requirements may result in attrition, including attrition of critically skilled labor, and difficulty securing future labor needs, which could materially and adversely affect the Company's results of operations, financial condition, and cash flows.

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

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

PGE owns and operates wind generating facilities, which generate federal production tax credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Company's wind facilities resulting in a material adverse impact on PGE's financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings.

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

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

Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, and increased risk of wildfires and can disrupt energy delivery, cause power outages, and damage the Company's facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load, and procure insurance related to such impacts. In response to more intense, frequent, and extreme weather events, PGE may need to make additional investments in generation, transmission, and distribution assets in order to enhance reliability and resiliency.

The greater size and prevalence of wildfires in Oregon in recent years could negatively affect public safety, customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, PGE's ability to access the wholesale energy market, PGE's ability to operate its generating facilities and transmission and distribution systems, the Company's costs to maintain, repair, and replace such facilities and systems, and recovery of costs. In addition, there is a risk that PGE may be unable to effectively implement a public safety power shutoff (PSPS) and de-energize its system in the event of heightened wildfire risk, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm.

Capital investment and operating expenses related to this risk may not be recoverable.

Reduced river flows can adversely affect generation from hydroelectric resources and unfavorable wind conditions can similarly affect wind generating resources. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

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

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

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

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

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

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

PGE has exposure to natural or human-caused disasters and other risks, including, but not limited to, earthquake, flood, ice, drought, extreme heat, lightning, wind, fire, accidents, equipment failure, acts of terrorism, computer system outages and other events. Such events could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

PGE could be vulnerable to cybersecurity attacks, data security breaches, physical security breaches, acts of terrorism, or other similar events that could disrupt its operations, require significant expenditures, or result in claims against the Company.

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that are deemed as critical infrastructure and depend on certain information technology systems. There is a risk that a goal of a cyber-attack is to cause large-scale disruption to the U.S. bulk power system or PGE operations and target the Company's computer systems, software, or networks to achieve such disruption. Despite the security measures in place, the Company's systems, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical security breaches, acts of terrorism, or other similar events that could disrupt operations, cause damage to the Company's generation, transmission, or distribution facilities, impact reliability of the transmission and distribution system, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGE's ability to initiate, authorize, process, record, and report financial information. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

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

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

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

The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines.

PGE's risk management procedures may not prevent or mitigate material losses.

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

Development of alternative technologies and changes in legislation and regulation may negatively impact the value of PGE's facilities.

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

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

The Company's ability to compete successfully depends heavily on its ability to ensure a continued and timely introduction of new products and new services to our customers as well as exploring new ways to further improve the reliability, efficiency, and flexibility of our power supply with innovative service offerings. Our operating results may be impacted if our products and services are not responsive to our customer needs or are burdened with significant regulatory complexities.

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

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

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

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

PGE's workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented under collective bargaining agreements. Workforce management risks include the risk of retaining key employees, turnover due to demographic challenges as employees approach retirement age, and turnover due to macroeconomic trends such as voluntary resignation of large numbers of employees similar to that experienced by other employers and industries since the beginning of the COVID-19 pandemic. PGE also faces competition from other employers for key skills and experience within the industry or local geography. The Company also faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize.

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

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

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2021 (in MW):

Facility	Location	Net Capacity (1)
Wholly-owned:		
Natural Gas or Oil:		
Beaver	Clatskanie, Oregon	510
Carty	Boardman, Oregon	438
Port Westward Unit 1 (PW1)	Clatskanie, Oregon	411
Coyote Springs	Boardman, Oregon	258
Port Westward Unit 2 (PW2)	Clatskanie, Oregon	225
Wind:		
Biglow Canyon	Sherman County, Oregon	450
Tucannon River	Columbia County, Washington	267
Wheatridge	Morrow County, Oregon	100
Hydro:		
North Fork	Clackamas River	58
Faraday	Clackamas River	46
Oak Grove	Clackamas River	45
River Mill	Clackamas River	25
T.W. Sullivan	Willamette River	18
Jointly-owned (2):		
Coal:		
Colstrip (3)	Colstrip, Montana	296
Hydro:		
Round Butte (4)	Deschutes River	230
Pelton (4)	Deschutes River	73
Net capacity		3,450

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.

(2) Net capacity reflects PGE's ownership share.

(3) PGE has a 20% ownership interest in the facility, which is operated by Talen Montana, LLC. The Company operated, and continues to have a 90% ownership interest in Boardman, which ceased coal-fired operations during the fourth quarter of 2020. For additional information on Colstrip as it relates to environmental laws and regulations in the state of Oregon, see *"RPS Standards and Other Laws"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

(4) PGE operates Pelton and Round Butte and has a 66.67% ownership interest as of December 31, 2021. Effective January 1, 2022, PGE sold 16.66% interest to the party who holds the remaining ownership interest, resulting in PGE's 50.01% ownership interest. For additional information on this sale of ownership interest in Pelton/Round Butte, see Note 20, Subsequent Events in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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

Transmission and Distribution

PGE owns or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2021, PGE-owned electric transmission system consisted of 1,274 circuit miles as follows: 287 circuit miles of 500 kV line; 415 circuit miles of 230 kV line; and 572 miles of 115 kV line. The Company also has 28,206 circuit miles of distribution lines that deliver electricity to its customers. The Company also has an ownership interest in, and capacity on, the following:

- 15% of the Colstrip Transmission facilities from Colstrip to BPA's transmission system; and
- 20% of the Pacific Northwest Intertie, a 4,800 MW transmission facility between the John Day Substation near the Columbia River in northern Oregon, and Malin, Oregon, near the California border. The Pacific Northwest Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to the following transmission capacity:

- 3,995 MW of firm BPA transmission on BPA's system to PGE's service territory in Oregon; and
- 150 MW of firm BPA transmission from the Mid-Columbia projects in Washington to the northern end of the Pacific Northwest AC Intertie, near John Day, Oregon, 5 MW to Tucannon River, and 5 MW to Biglow Canyon.

Non-utility Real Estate

PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. As of December 31, 2021, the non-utility property, plant, and equipment balance, net of accumulated depreciation was $71 million, recorded in Other noncurrent assets on the Company's consolidated balance sheets in Item 8.—"Financial Statements and Supplementary Data."

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

ITEM 3. LEGAL PROCEEDINGS.

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

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

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

PGE's common stock is traded on the NYSE under the ticker symbol "POR". As of February 7, 2022, there were 624 holders of record of PGE's common stock.

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

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

Share repurchase program

On February 17, 2021, the Company's Board of Directors authorized a share repurchase program, under which the Company is authorized to repurchase up to $17.5 million of its outstanding common stock through 2022. As of December 31, 2021, the Company had repurchased 250,000 shares at an average price of $48.67 per share for a total cost of $12.2 million under this program. All share repurchases were made under PGE's publicly announced program and there were no other programs under which the Company repurchased shares. PGE did not repurchase any shares of its common stock during the three-month period ended December 31, 2021.

On February 11, 2022, the Company's Board of Directors authorized a share repurchase program, replacing and superseding the program previously authorized on February 17, 2021, under which the Company is now authorized to repurchase up to 350,000 shares of its outstanding common stock at a maximum share price of $60, resulting in maximum aggregate purchase price of $21 million through 2022. The share repurchase program may be limited or terminated at any time without prior notice. Under the share repurchase program, the Company may repurchase shares of common stock from time to time in open market transactions or in privately negotiated transactions as permitted under applicable rules and regulations. The extent to which the Company repurchases its shares of common stock and the timing of such purchases will depend upon market conditions and other considerations as may be determined in the Company's sole discretion.

ITEM 6. [RESERVED]

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

Forward-Looking Statements

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

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

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

- governmental policies, legislative action, and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs, and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- inflation and interest rates;
- changing customer expectations and choices that may reduce customer demand for its services may impact PGE’s ability to make and recover its investments through rates and earn its authorized return on equity, including the impact of growing distributed and renewable generation resources, changing customer demand for enhanced electric services, and an increasing risk that customers procure electricity from registered ESSs or community choice aggregators;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Regulatory Matters of the “Overview” in this Item 7. and Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.— “Financial Statements and Supplementary Data” of this Annual Report on Form 10-K;
- natural or human-caused disasters and other risks, including, but not limited to, earthquake, flood, ice, drought, extreme heat, lightning, wind, fire, accidents, equipment failure, acts of terrorism, computer system outages and other events that disrupt PGE operations, damage PGE facilities and systems, cause the release of harmful materials, cause fires, and subject the Company to liability;
- unseasonable or extreme weather and other natural phenomena, such as the greater size and prevalence of wildfires in Oregon in recent years, which could affect public safety, customers’ demand for power and PGE’s ability and cost to procure adequate power and fuel supplies to serve its customers, PGE’s ability to access the wholesale energy market, PGE’s ability to operate its generating facilities and transmission and distribution systems, the Company’s costs to maintain, repair, and replace such facilities and systems, and recovery of costs;
- PGE’s ability to effectively implement a PSPS and de-energize its system in the event of heightened wildfire risk, which could lead to potential liability if energized systems are involved in wildfires that cause harm;
- operational factors affecting PGE’s power generating facilities and battery storage facilities, including forced outages, unscheduled delays, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- complications arising from PGE’s jointly-owned plant, including changes in ownership, adverse regulatory outcomes or legislative actions, or operational failures that result in legal or environmental liabilities or unanticipated costs related to replacement power or repair costs;

- delays in the supply chain and increased supply costs, failure to complete capital projects on schedule and within budget, failure of counterparties to perform under agreements, or the abandonment of capital projects, any one of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices that could require PGE to post additional collateral or issue additional letters of credit pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, whether global or local in nature, including unseasonable or extreme weather and other natural phenomena that may affect energy costs or consumption, increase the Company's costs, cause damage to PGE facilities and system, or adversely affect its operations;
- changes in residential, commercial, or industrial customer growth, or demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- cybersecurity attacks, data security breaches, physical security breaches, or other malicious acts that cause damage to the Company's generation, transmission, or distribution facilities, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, or result in the release of confidential customer, vendor, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the ability to recruit and retain key employees and other talent due to COVID-19 mandates and turnover due to macroeconomic trends such as voluntary resignation of large numbers of employees similar to that experienced by other employers and industries since the beginning of the COVID-19 pandemic;
- new federal, state, and local laws that could have adverse effects on operating results;
- political and economic conditions;
- the impact of widespread health developments, including the global coronavirus (COVID–19) pandemic, and responses to such developments (such as voluntary and mandatory quarantines, including government stay at home orders, as well as shut downs and other restrictions on travel, commercial, social, and other activities), which could materially and adversely affect, among other things, demand for electric services, customers' ability to pay, supply chains, personnel, contract counterparties, liquidity and financial markets;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

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

OVERVIEW

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

PGE is a vertically-integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon. In addition, the Company participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to meet the needs of, and obtain reasonably-priced power for, its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory.

Company Strategy

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

- Decarbonize the power supply by reducing GHG emissions associated with the power served to customers by at least 80% by 2030, and achieving zero GHG emissions associated with the power served to customers by 2040;
- Electrify other sectors of the economy like transportation and buildings that are also transforming to reduce GHG emissions; and
- Perform by improving work efficiency, safety of our coworkers, and reliability of our systems and equipment, all while adhering to the Company's earnings per diluted share growth guidance of 4-6% on average.

Climate change

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

In response to the state of Oregon's GHG reduction targets to combat climate change, PGE estimates by 2030 it will need to acquire approximately 1,500 to 2,000 MW of clean and renewable resources and approximately 800 MW of non-emitting dispatchable capacity resources. For more information see "The Resource Planning Process" within Investing in a clean energy future section of this Overview.

***The Climate Pledge*—**On April 21, 2021, PGE joined The Climate Pledge, a commitment to be net-zero annual carbon emissions by 2040, which is a decade ahead of the Paris Agreement's goal of 2050. As a signatory to The Climate Pledge, PGE agrees to: i) measure and report GHG emissions on a regular basis; ii) implement decarbonization strategies in line with the Paris Agreement through real business changes and innovations, including efficiency improvements, renewable energy, materials reductions, and other carbon emission elimination strategies; and iii) neutralize any remaining emissions with additional, quantifiable, real, permanent, and socially-beneficial offsets.

Empowering customers and communities—PGE's customers are committed to purchasing clean energy, as over 235 thousand residential and small commercial customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. In 2017, Oregon's most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area continue to consider similar goals.

In response, the Company implemented a new customer service option, the GFI Program, which allows for 100 MW of PGE-provided PPAs for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in the first quarter of 2019, the program provides business customers access to bundled renewable attributes from those resources. On March 29, 2021, the OPUC issued an order that expanded the program by 200 MW and provided for the possibility of PGE ownership of the underlying renewable resources under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable integrated power while providing customer choice and a cleaner energy system.

In December 2021, the OPUC issued an order, which approved a petition to increase capacity under the customer-provided renewable resources by 250 MW, which would bring the total available capacity under the program to 750 MW.

Extreme weather—In recent years, PGE's territory has experienced unprecedented heat, historic ice and snowstorms, and wildfires. In June 2021, temperatures in the region reached all-time recorded highs, shattering the Company's previous peak load demand, and surpassing the prior summer peak load by nearly 12% (see the Operating Activities section of this Overview for more information on the impacts to PGE's results of operation). In February 2021, PGE's service territory experienced an ice storm, which led to historical levels of customer power outages, and caused considerable expense for service restoration and damage repair (see "February 2021 Ice Storms and Damage" of the Regulatory Matters section of this Overview for more information on the impact to PGE's results of operation). In 2020, Oregon experienced one of the most destructive wildfire seasons on record, with over one million acres of land burned (see "Wildfire" of the Regulatory Matters section of this Overview for more information on the impact to PGE's results of operation). The increase and severity of extreme weather events highlights the importance of combating the effects of climate change through decarbonizing the power supply and investing in a more reliable and resilient grid.

Investing in a clean energy future

Building a resilient grid— Recent extreme weather events driven by changes to global systems affecting rainfall patterns and seasonal snow cover in the region have impacted PGE's customers significantly, and the frequency and severity of these events are accelerating. PGE's grid of the future is increasingly smart and adaptive, so that the electric service its customers depend on remains reliable even under uncertain and extreme conditions. For example, the Company uses wireless smart sensors and centrally controlled automated switches to help isolate disruptions and more quickly reroute power, preventing or shortening disruptions. In the field, PGE uses advanced data analytics to optimize system investments and maintenance. The Company is updating its design standards, so that smart sensors and switches are constructed to withstand more extreme weather, particularly in high-risk wildfire areas. Highlights of PGE's key investments and plans for building a resilient grid are as follows:

- <u>Integrated Operations Center (IOC)</u> — In the fourth quarter of 2021, PGE placed in-service the IOC with a total investment of $175 million, including an allowance for funds used during construction (AFUDC). The

IOC will centralize mission-critical operations, including those that are planned as part of the integrated grid strategy. This secure, resilient facility will include infrastructure to support and enhance grid operations and co-locate primary support functions. Acting as the nerve center of PGE's system, the IOC will enable the Company to apply smart technologies to keep an increasingly complex set of clean energy resources operating efficiently. The system integrations at the IOC will strengthen physical and cyber security of the system to meet critical infrastructure standards, such as seismic and other natural disaster readiness, with the aim of achieving greater reliability with fewer and shorter outages.

- *Advanced Distribution Management System (ADMS)* – In the fourth quarter of 2021, PGE placed in-service a new software platform called the ADMS with a total investment of $30 million. The ADMS is designed to allow the Company to reduce outages by proactively detecting and responding to issues before they impact customers and providing self-healing technology for restoring power.
- *Distribution System Plan (DSP)* - PGE filed its inaugural DSP on October 15, 2021, which lays out plans to build a grid that empowers customers to make energy management choices to support decarbonization and supports a two-way energy ecosystem with resources like batteries, two-way EV charging, and solar panels where communities—especially underserved Oregonians—need them.

The Resource Planning Process—PGE's resource planning process includes working with customers, stakeholders, and regulators to chart the course toward a clean, affordable, and reliable energy future. This process includes consideration of customer expectations and legislative mandates to move away from fossil fuel generation and toward renewable and clean sources of energy. PGE's 2016 IRP process resulted in the development of the following renewable resources:

- *Wheatridge Renewable Energy Facility*—In 2018, the Company issued a request for proposals (RFP) seeking to procure approximately 100 average megawatts (MWa) of qualifying renewable resources. The prevailing bid was Wheatridge, an energy facility in eastern Oregon that will combine 300 MW of wind generation and 50 MW of solar generation with 30 MW of battery storage. Construction on the solar and battery components is ongoing and expected to be completed in early 2022. PGE owns 100 MW of the wind resource, which was placed in-service in the fourth quarter of 2020. Subsidiaries of NextEra Energy Resources, LLC own the balance of the wind resource, along with the solar and battery components, and will sell their portion of the output to PGE.

In May 2020, the OPUC issued an order that acknowledged the Company's 2019 IRP and the Action Plan for PGE to undertake over the next four years to acquire the resources identified. The order also required that PGE consider resources in the Renewable and Capacity RFPs in a co-optimized manner. PGE had requested authorization to pursue up to approximately 700 MW of capacity contribution by 2025 from a combination of renewables, existing resources, and new non-emitting dispatchable capacity resources, such as energy storage. As a result, the following resources were procured:

- *Douglas County PUD*—PGE entered into an agreement with Douglas County PUD during 2020 to supply the Company additional capacity from facilities including the Wells Hydroelectric Project, located on the Columbia River in central Washington. With a start date of January 1, 2021, the five-year agreement is expected to contribute between 100 and 160 MW toward a capacity need that PGE identified in its 2019 IRP; and
- *CTWS*—As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the CTWS. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGE's ownership interest in the project is 50.01%. Also on June 30, 2021, PGE executed a 16-year PPA with the CTWS that would commence in 2025 to purchase 100% of their current, and potential future, share of the project's output. For more information see *"CTWS"* within Purchased Power in the Power Supply section of Item 1.—"Business."

To meet the remaining capacity need identified in the 2019 IRP, the Company is seeking to procure both renewable and non-emitting, dispatchable resources in an All-Source RFP. PGE estimates that it will need to nearly triple the amount of clean and renewable energy currently serving customers to meet the Company's 2030 emissions reduction target, in addition to removing coal from its portfolio. As a result, PGE estimates by 2030 it will need approximately 1,500 to 2,000 MW of clean and renewable resources and approximately 800 MW of non-emitting dispatchable capacity resources. PGE is working to exit Colstrip by the end of 2025. On October 15, 2021, PGE initiated its 2021 All-Source RFP public process, seeking approximately 1,000 MW of renewable and non-emitting resources. PGE will work with the OPUC to evaluate the opportunity to procure additional resources through this RFP, with a potential target of getting up to one-third of the clean resources needed to meet the 2030 emissions reduction target. The All-Source RFP seeks:

- *Renewables*—PGE expects to bring on approximately 375 to 500 MW of renewable resources;
- *Non-emitting capacity*—PGE will also be seeking approximately 375 MW on non-emitting dispatchable capacity resources that can be used on the hottest or the coldest days of the year; and
- *GFI Program*—PGE expects to procure a resource or resources for the Company's GFI Program through the 2021 All-Source RFP. Under the GFI Program, PGE can procure up to 100 MW of a new wind, solar, or hybrid renewable and battery storage resource to meet subscriber demand under the PGE supply option. The Company does not expect GFI Program resources considered in the 2021 All-Source RFP to contribute towards the cost-of-service 150 MWa energy cap envisioned under the 2019 IRP Action Plan, although that is subject to OPUC discretion.

Renewable resources in PGE's 2021 All-Source RFP must be RPS eligible, qualify for the federal PTC or the federal Investment Tax Credit, and pass the cost-containment screen. All resources (dispatchable or renewable) must be online by the end of 2024, with certain exceptions for long-lead time pumped hydro resources.

PGE issued the final RFP after receiving approval from the OPUC in December 2021, with a submission deadline for proposals in January 2022. The RFP seeks to add 375 to 500 MW of renewables and 375 MW of non-emitting capacity by the end of 2024. Among the conditions, the OPUC will require PGE to consider bid submissions that would propose to repower existing generation resources. Bids will be evaluated based on the OPUC-approved scoring methodology. Following determination of a final shortlist, PGE plans to file for acknowledgement during April 2022 with a final selection in June.

On October 15, 2021, PGE filed an extension waiver for the next IRP, which the OPUC approved. As a result, the next IRP would be filed for OPUC consideration by March 31, 2023.

Electrify other sectors of the economy—PGE is working toward an equitable, safe, and clean energy future. Recent and future enhancements to the grid to enable a seamless platform include:

- The use of electricity in more applications such as electric vehicles and heat pumps;
- The integration of new, geographically-diverse energy markets;
- The deployment of new technologies like energy storage, communications networks, automation and control systems for flexible loads, and distributed generation;
- The development of connected neighborhood microgrids and smart communities; and
- The use of data and analytics to better predict demand and support energy-saving customer programs.

The Company is also working to advance transportation electrification, partnering with local mass transit agencies to transition to a greater use of electric vehicles, and developing projects aimed at improving accessibility to electric vehicle charging stations. In June 2019, the Oregon Legislature enacted Oregon Senate Bill 1044, which establishes Oregon's zero-emissions vehicle goals in statute at 250 thousand zero-emission vehicle sales by 2025 and 90% of all new vehicle sales to be zero-emission by 2035. In September 2019, PGE filed with the OPUC its first

Transportation Electrification plan, which considers current and planned activities, along with both existing and potential system impacts, in relation to the State's carbon reduction goals. In October 2020, the OPUC approved the plan and related costs and revenues associated with the Transportation Electrification and Electric Vehicle Charging pilot programs. In 2021, the Oregon legislature enacted House Bill 2165, ensuring the OPUC has clear and broad authority to allow electric company investments in infrastructure to support transportation electrification.
PGE also partnered with Daimler Trucks North America to open Electric Island, a first-of-its-kind heavy-duty electric truck charging site. The project is also one of the first sites deployed in the multi-utility, I-5 transit Corridor Project that will install heavy duty electric vehicle charging stations along I-5 from Canada to Mexico. In addition, PGE is working with the City of Portland to install charging systems on existing power poles, and the Company helped bring the first electric school buses to Oregon's roads.

Environmental Laws and Regulations

House Bill 2021—In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions associated with electricity sold to Oregon consumers to 80% below baseline emissions levels by 2030, 90% below baseline emissions levels by 2035, and 100% below baseline emissions levels by 2040. The baseline period for the investor-owned utilities is the average annual GHG emissions for the years 2010, 2011, and 2012 associated with the electricity sold to retail electricity consumers as reported to Oregon Department of Environmental Quality (ODEQ).

Utilities must develop a clean energy plan (CEP) for meeting the targets concurrent with the development of each IRP. In reviewing the CEP, the OPUC must ensure that utilities demonstrate continual progress and are taking actions as soon as practicable that facilitate rapid reduction of GHG emissions at reasonable costs to retail electricity consumers. The OPUC is also given authority to apply a performance incentive for early compliance with one or more of the clean energy targets.

Regulated entities will continue to report annual GHG emissions to ODEQ, as they do today. In compliance years, which are 2030, 2035, and 2040 and every year thereafter, the OPUC will use the data reported to ODEQ for that compliance year to determine whether the reduction targets are met. In determining compliance, if the utility has emissions in excess of the target, the OPUC must take into consideration emissions attributable to meeting load if the utility experienced unexpected challenges, such as transmission constraints or under-production from hydro and other renewable resources. The bill also includes certain compliance exceptions to protect customers, such as cost caps and mandatory reliability standards.

The legislation also:

- Aligns with PGE decarbonization goals while protecting affordability and reliability;
- Establishes clear decarbonization authority for the OPUC, including authority over ESSs;
- Modernizes competition provisions of Oregon's electricity restructuring law from 1999, Oregon Senate Bill 1149 (SB 1149),
- Provides clear authority and process for a community-wide green tariff program for customers 30 kilowatts and smaller and allows utilities the ability to earn a return on investments in program resources, and
- Codifies non-bypassability of costs to ensure all customers pay their share of HB 2021 policy costs.

Governor Executive Orders—In March 2020, the Governor of Oregon issued an executive order directing state agencies to seek to reduce and regulate GHG emissions. As the Governor is limited by current statutory authority, the executive order did not include a market-based mechanism as envisioned by the cap and trade legislation introduced in prior legislative sessions.

Among other things, the executive order:

- Directed state agencies to integrate climate change and the State's GHG emissions reduction goals into their planning, budgets, investments, and decisions to the extent allowed by law.
- Directed the OPUC to—
    - determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's reduction goals;
    - encourage electric companies to support transportation electrification infrastructure that supports GHG emissions reductions and zero-emission vehicle goals; and
    - prioritize proceedings and activities that advance decarbonization in the utility sector and exercise its broad statutory authority to reduce GHG emissions, mitigate energy burden on utility customers, and ensure reliability and resource adequacy.
- Directed the ODEQ to adopt a program to cap and reduce GHG emissions from large stationary sources, transportation fuels, and other liquid or gaseous fuels including natural gas. The ODEQ adopted such a program, referred to as the Climate Protection Plan, on December 16, 2021; and
- More than doubled the reduction goals of the state's Clean Fuels Program and extended the program, from the previous rule that required a ten percent reduction in average carbon intensity of fuels from 2015 levels by 2025, to a 25 percent reduction below 2015 levels by 2035.

RPS Standards and Other Laws—In 2016, SB 1547 set a benchmark for how much electricity must come from renewable sources and required the elimination of coal from Oregon utility customers' energy supply no later than 2030 (subject to an exception that allowed extension of this date until 2035 for PGE's output from Colstrip).

Other provisions of the law include:

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

In response to SB 1547, the Company filed a tariff request in 2016 to accelerate recovery of PGE's investment in Colstrip from 2042 to 2030. In January 2020, the owners of Colstrip Units 1 and 2 permanently retired those two units. Although PGE has no direct ownership interest in those two units, the Company does have a 20% ownership share in Colstrip Units 3 and 4, which utilize certain common facilities with Units 1 and 2.

Although PGE is currently scheduled to recover the costs of Colstrip by 2030, some co-owners of Units 3 and 4 have sought approval to recover their costs sooner in their respective jurisdictions. In December 2021, the OPUC approved PGE's depreciation study (OPUC Docket UM 2152), which will accelerate depreciation on Colstrip through December 31, 2025. Depreciation rates will change and customer collection would coincide with the price effective date of the Company's pending 2022 General Rate Case (2022 GRC). For further information on the 2022 GRC, see *"General Rate Case"* in the "Regulatory Matters" section of this Overview. The Company continues to evaluate its ongoing investment in Colstrip, including the possibility of PGE's exit from the facility. See Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" for information regarding legal proceedings related to Colstrip.

Any reduction in generation from Colstrip has the potential to provide capacity on the Colstrip Transmission facilities, which stretch from eastern Montana to near the western end of that state to serve markets in the Pacific Northwest and neighboring states. PGE has a 15% ownership interest in, and capacity on, the Colstrip Transmission facilities. Renewable energy development might benefit from any excess transmission capacity that may become available.

As previously planned, in October 2020, PGE ceased coal-fired operation at its Boardman generating plant and has begun decommissioning activities.

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

Regulatory Matters

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

General Rate Case**—**On July 9, 2021, PGE filed with the OPUC a general rate case based on a 2022 test year. The filing requests an increase in PGE's annual revenue requirement that, when combined with changes in supplemental schedules, results in an overall average increase of approximately 3.9% in customer prices for 2022. The net price increase and annual revenue requirement includes a 2.0% average price increase as a result of higher net variable power costs expected in 2022, as reflected in the AUT filed with the OPUC in April 2021. The GRC filing seeks recovery of base business investments in upgrading the grid to improve reliability, resiliency, and capability to deliver safe, reliable, clean electricity to customers.

PGE has invested heavily in its transmission and distribution system to meet the needs of customers by addressing new and growing load and strengthening the grid for new challenges with extreme weather and wildfires. These investments include needed pole and underground wire replacements, substation upgrades, and other additions, as well as the new IOC and ADMS software platform (see “*Building a resilient grid*” section of Investing in a clean energy future within this Overview.)

The GRC also reflects significant investments geared toward protecting the lives and property of Oregonians. As Oregon’s weather gets hotter and drier, increasing the risk of catastrophic wildfires, the Company is intensifying efforts to keep the system safe from wildfire-related events and resilient from weather and disaster-related crises. Key to these efforts are expansion of the vegetation management program and system hardening to help mitigate potential outages arising from wildfire and severe weather year-round.

The proposed net increase in annual revenue requirement in the 2022 GRC was based upon:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.5%;
- A cost of capital of 6.94%; and
- A rate base of $5.7 billion.

PGE, OPUC staff, and certain customer groups reached an agreement that resolves cost of capital issues and allows for:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.5%; and
- A cost of capital of 6.83%, which reflects updates for actual and forecasted debt costs.

In addition, on January 18, 2022, PGE, OPUC staff, and certain customer groups filed a stipulation with the OPUC reflecting an agreement that resolves the annual revenue requirement, average rate base, and corresponding increase authorized in customer prices. Certain elements of the case remain unsettled.

The latest agreement reflects a final revenue requirement that is based upon an average rate base of $5.6 billion and an annual revenue requirement increase of $74 million consisting of the following changes (in millions):

As filed (includes $40 million related to Net Variable Power Costs)		$	99
Load and Net Variable Power Cost Updates			16
Base Business Revenue Requirement Updates:			
Faraday hydro capital-related revenue requirement (1)	(18)		
Cost of debt settlement including reductions to reflect actual financing	(7)		
Level III outage annual regulatory accrual (2)	(7)		
Other reductions to rate base and O&M	(5)		
Other various modifications to reflect actual costs	(4)		
Subtotal			(41)
As revised (includes $64 million related to Net Variable Power Costs) (3)		$	74

(1) The Faraday improvement capital project will not be placed in-service as of May 9, 2022, and the capital-related revenue requirement has been removed and will be addressed in future ratemaking proceedings. As of December 31, 2021, the CWIP balance associated with Faraday was $109 million, including AFUDC.

(2) PGE is authorized to collect annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. In the 2022 GRC, the Company requested an annual collection increase from $4 million to $11 million, and agreed to retain the annual collection at $4 million.

(3) Total revenue requirement increase to base rates is $83 million, of which $9 million is not considered incremental as it is already included in current customer prices.

Further, the agreement with parties would eliminate PGE's decoupling mechanism upon the effective date of new customer prices pursuant to this case. In 2022, estimated collections from, or refunds to, customers will be pro-rated based on the effective date of new customer prices per the 2022 GRC and expected to be amortized in customer prices in 2024 over a one-year period. The decoupling mechanism provides a means of recovery or refund of margin lost or gained as a result of changes in weather-adjusted energy use per customer in comparison to levels projected in customer prices. For further information on the decoupling mechanism, see *"Decoupling"* in this Overview section.

All the agreements remain subject to OPUC approval. PGE will continue to work with parties throughout this proceeding to resolve all remaining unsettled elements of the case.

PGE has proposed that new customer prices become effective May 9, 2022. Price changes for the AUT and the supplemental schedule items occurred January 1, 2022.

Regulatory review of the 2022 GRC will continue, with a final OPUC order expected to be issued by April 2022. Management cannot predict the ultimate outcome of the case.

More information about the 2022 GRC filing (OPUC Docket UE 394) is available on the OPUC Internet website at www.oregon.gov/puc.

***COVID-19 Impacts*—**The COVID-19 pandemic has had a variety of adverse impacts on economic activity. The Company has responded to the hardships many customers are facing and has taken steps to support its customers and communities, including temporarily suspending disconnections and late fees during the crisis, developing time payment arrangements, and partnering with local non-profits to soften the impacts on small businesses and low-income residential customers. As a result of these activities and economic hardships, PGE has experienced an increase in bad debt expense, lost revenue, and other incremental costs.

In March 2020, PGE filed an application with the OPUC for deferral of lost revenue and certain incremental costs, such as bad debt expense, related to COVID-19. The application requested the ability to defer incremental costs associated with the COVID-19 pandemic but did not specify the precise scope of the deferral, or the means by which PGE would recover deferred amounts. PGE, other utilities under the OPUC's jurisdiction, intervenors, and OPUC staff held discussions regarding the scope of costs incurred by utilities that may qualify for deferral under Docket UM 2114. The result of such discussions was an Energy Term Sheet (Term Sheet), which dictates costs in scope for deferral but is silent to the timing of recovery of such costs. In September 2020, the OPUC adopted a proposed OPUC Staff motion for Staff to execute stipulations incorporating the terms of the Term Sheet. PGE's deferral application was approved by the OPUC in October 2020 with final stipulations for the Term Sheet approved in November 2020.

For the year ended December 31, 2021, PGE recorded a $26 million net increase to its COVID-19 deferral. As of December 31, 2021 and December 31, 2020, PGE's deferred balance was $36 million and $10 million, respectively, comprised primarily of bad debt expense in excess of what is currently considered and collected in customer prices. Incremental bad debt expense was $29 million for the year ending 2021. Amortization of any deferred costs will remain subject to OPUC review prior to amortization in customer prices and would be subject to an earnings review.

PGE believes the full amount of the 2020 and 2021 deferrals is probable of recovery as the Company's prudently incurred costs were in response to the unique nature of the COVID-19 pandemic health emergency. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

In June 2020, the FERC issued a waiver that provides that, for the 12-month period starting March 2020, jurisdictional utilities may apply an alternative AFUDC calculation formula that excludes the actual outstanding short-term debt balance and replaces it with the simple average of the actual 2019 short-term debt balance. The purpose of the waiver is to allow relief to utilities that issued short-term debt in response to the COVID-19 emergency and the detrimental impacts the issuance of short-term debt has on the allowance for equity funds used during construction. PGE adopted the waiver in the second quarter of 2020 and retrospectively applied its provisions as of March 2020. On February 23, 2021, FERC issued an order extending the waiver an additional seven months, to be effective March 1, 2021 through September 30, 2021. On September 21, 2021, FERC issued an additional order to further extend the waiver through March 31, 2022. PGE has adopted all waiver extensions.

***Wildfire*—**In 2020, Oregon experienced one of the most destructive wildfire seasons on record, with over one million acres of land burned. PGE's wildfire mitigation planning includes regular system-wide risk assessment, which led to the identification and activation of a PSPS in a zone near Mt. Hood that was identified as a region at high risk of wildfire in 2020. Additionally, in response to wildfires across Oregon in 2020, PGE cut power to eight additional high-risk fire areas in partnership with local and regional agencies. The Oregon Department of Forestry has opened an investigation into the causes of wildfires in Clackamas County. The Company has received a subpoena and is fully cooperating. The Company is not aware of any wildfires caused by PGE equipment.

The Company is intensifying efforts on its system to increase wildfire safety and resiliency to weather and other disaster-related crises. These efforts include enhanced tree and brush clearing, replacing equipment, and making emergency plans in close partnership with local, state, and federal land and emergency management agencies to further expand the use of a PSPS, if the need should arise. Pursuant to Oregon Senate Bill 762, which was passed in June 2021, PGE submitted a risk-based wildfire protection plan to the OPUC in December 2021.

PGE continues to incur costs to replace and rebuild PGE facilities damaged by the fires that occurred in 2020, as well as addressing fire-damaged vegetation and other resulting debris and hazards both in and outside of PGE's property and right-of-way. In October 2020, the OPUC formally approved PGE's request for deferral of such costs.

As of December 31, 2021 and December 31, 2020, PGE's cumulative deferred costs related to the wildfire response was $45 million and $15 million, respectively. PGE continues to assess the damage to its infrastructure and expects regulatory recovery of prudently incurred restoration costs. PGE believes the full amount of the 2020 and 2021 deferrals is probable of recovery as the Company's prudently incurred costs were in response to the unique and unprecedented nature of the wildfire events leading to the deferral. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

February 2021 Ice Storms and Damage—Beginning on February 11, 2021, an historic set of storms involving heavy snow, winds and ice impacted the United States, including PGE's service territory. On February 13, 2021, Oregon's Governor declared a state of emergency due to severe winter weather that resulted in heavy snow and ice accumulation, high winds, critical transportation failures, and loss of power and communications capabilities. The wind and ice from the storms caused significant damage to PGE's transmission and distribution systems, which resulted in over 750,000 outages, with many customers affected more than once. At peak activity during the recovery, PGE deployed over 400 repair crews across the service territory, with many of these crews provided through mutual aid arrangements from throughout the West.

Through December 31, 2021, PGE has incurred an estimated $105 million in incremental costs due to the storms, of which $36 million were capital and recorded to Electric utility plant, net and $69 million were operating expenses associated with transmission and distribution. Beginning in 2019, the OPUC authorized the Company to collect $4 million annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. In response to the February storms, PGE exhausted its storm collection balance for 2021 of $9 million, which was used to offset operating expenses. In December 2021, PGE and parties in the 2022 GRC reached a settlement, subject to OPUC approval, to restore the storm collection balance for the $9 million used in 2021 and to defer the resulting balance of $9 million into the February 2021 ice storm and damage regulatory asset.

On February 15, 2021, PGE filed an application for authorization to defer emergency restoration costs for the February storms (Docket UM 2156) and as of December 31, 2021, the Company has deferred a total of $67 million, including interest, related to incremental operating expenses due to the storms. PGE incurred and deferred costs related to replacing and rebuilding PGE facilities damaged by the storms, as well as addressing vegetation and other resulting debris and hazards both in and outside of PGE's property and right-of-way. PGE expects an OPUC decision on the February storms deferral in the first quarter of 2022. While the Company believes the full amount of the deferral is probable of recovery given PGE's prudently incurred costs were in response to the unique and unprecedented nature of the storms, the OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery.

Declared states of emergency—On September 22, 2021, the OPUC issued an order that approved a pre-authorized deferral of costs associated with declared states of emergency. Qualifying events would include federal or state declared emergencies with impacts on PGE's service territory. Previously the Company had to file a request for deferred accounting when an event of that nature occurred, and had to seek OPUC approval of such deferred accounting applications to be effective. With this order, PGE would provide notice of an event that qualifies within 30 days of the declared state of emergency and would not need to seek OPUC approval to use deferred accounting to track incremental costs related to the emergency. The OPUC maintains responsibility to review utility requests to amortize deferred amounts in customer prices including a review of utility prudence in a future proceeding, among other requirements. As of December 31, 2021, PGE has not recorded any costs under this deferral order.

Power Costs—Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. As approved by the OPUC, the 2021 AUT included a final increase in power costs for 2021, and a corresponding increase in annual revenue requirement, of $66 million from 2020 levels, which were reflected in customer prices effective January 1, 2021. The 2022 AUT contains a $64 million increase in NVPC that will be recovered in customer prices beginning January 1, 2022. For 2021, actual NVPC was above baseline NVPC by $62 million, which was outside the established deadband range. Pursuant to the PCAM and related earnings test, as of December 31, 2021, PGE has deferred $29 million, which represents 90% of the excess variance expected to be collected from customers. See "*Power Operations*" within this Overview section of Item 7 for more information regarding the PCAM.

***Portland Harbor Environmental Remediation Account (PHERA) Mechanism*—**The EPA has listed PGE as one of over one hundred PRPs related to the remediation of the Portland Harbor Superfund site. As of December 31, 2021, significant uncertainties still remained concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. In a Record of Decision issued in 2017, the EPA outlined its selected remediation plan for clean-up of the Portland Harbor site, which had an estimated total cost of $1.7 billion. Stakeholders have raised concerns that EPA's cost estimates are understated, and PGE estimates undiscounted total remediation costs for Portland Harbor per the ROD could range from $1.9 billion to $3.5 billion. The Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of Portland Harbor. However, the Company may obtain sufficient information, prior to the final determination of allocation percentages among PRPs, to develop a reasonable estimate, or range, of its potential liability that would require recording an estimate, or low end of the range. The Company's liability related to the cost of remediating Portland Harbor could be material to PGE's financial position. The impact of such costs to the Company's results of operations is mitigated by the PHERA mechanism. As approved by the OPUC, the Company's recovery mechanism allows the Company to defer and recover estimated liabilities and incurred environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, including, but not limited to, insurance recoveries, and customer prices, as necessary. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds, and annual expenditures in excess of $6 million, excluding contingent liabilities, are subject to an annual earnings test. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or disallowed per the prescribed earnings test. For further information regarding the PHERA mechanism, see "EPA Investigation of Portland Harbor" in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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

Collections under the decoupling mechanism are subject to an annual limitation of 2% of revenues for each eligible customer class, based on the net prices in effect for the applicable tariff schedule at the time of collection. For collections recorded in 2021, the 2% limit will be applied to the net prices for the applicable tariff schedules that will be in effect on January 1, 2023. The Company reached its 2021 limit for collection from commercial customers during the third quarter of 2021. No limit exists for any potential refunds under the decoupling mechanism, thus increased demand from residential customers since the onset of the COVID-19 pandemic has resulted in larger estimated refunds under the decoupling mechanism, which have largely offset the revenue increases that have resulted from higher residential demand.

In the 2022 GRC, parties reached an agreement that would eliminate PGE's decoupling mechanism upon the effective date of new customer prices pursuant to the case, which are expected to begin in May 2022. Subject to approval by the OPUC, which is expected in a final order by April 2022, deferrals would cease, although amortization of previously recorded deferrals would continue as scheduled until collected or refunded in future customer prices.

For the year ended December 31, 2021, the Company recorded an estimated refund of $17 million and a collection of $7 million from residential and commercial customers, respectively, that resulted from variances between actual weather-adjusted use per customer and that projected in the 2019 GRC. The Company continues to see higher weather-adjusted use per customer from residential customers that are spending more time at home and lower use per customer from commercial customers that are adversely affected by COVID-19.

At December 31, 2020, PGE had recorded a total refund of $6 million that will be refunded to customers over a one-year period, which began January 1, 2022.

Deferral of Boardman Revenue Requirement—In October 2020, intervenors filed a deferral application with the OPUC that would require PGE to defer and refund the revenue requirement associated with Boardman currently included in customer prices as established in the Company's 2019 GRC. The application states a deferral is required for customers to adequately capture the reduction in revenue requirement beginning on October 15, 2020, the date Boardman ceased operations. On October 7, 2021, intervenors filed a motion with the OPUC requesting to consolidate the open Boardman deferral docket with PGE's open 2022 GRC docket. Combining the dockets would provide an avenue under which the OPUC could make a separate decision on the issues associated with the Boardman deferral within PGE's 2022 GRC docket. PGE objected to the request by intervenors on the basis that the two dockets are not similar enough to warrant consolidation and would have the effect of expanding the scope and complicating the 2022 GRC proceeding. The Administrative Law Judge denied the consolidation, although did provide an opportunity to use the 2022 GRC proceeding to settle any issues with deferrals. How the Boardman deferral will be resolved in relation to the 2022 GRC proceeding remains uncertain and management is currently unable to predict the outcome. PGE continues to work with the OPUC and parties to establish an appropriate schedule and process to allow for a fair determination of the Boardman deferral and the 2022 GRC.

Pursuant to the deferral application, PGE estimates the potential deferral to be $14 million for the period ended December 31, 2020 plus an additional $66 million for the year ended December 31, 2021. As of December 31, 2021, PGE has not recorded a regulatory liability pursuant to this deferral application as the Company believes its current prices are just and reasonable in light of PGE's continued substantial investments in utility plant. The costs of these continued investments, which are not currently reflected in customer prices, more than offset the revenue requirement for Boardman. If the OPUC authorizes a refund, PGE would record a regulatory liability with a corresponding charge to earnings.

Depreciation Study—In December 2021, PGE received an OPUC order approving revised depreciation rates based on 2019 data. The new rates will be incorporated in PGE's 2022 GRC and expected to be effective May 9, 2022.

The OPUC order also approved the acceleration of depreciation expense and corresponding recovery on Colstrip generation assets from December 31, 2030 to December 31, 2025. The resulting depreciation rates are expected to go into effect when new customer prices go into effect in May 2022, in conjunction with the 2022 GRC.

The order also includes cost recovery of $4 million for updated ARO-related decommissioning costs related to PGE's T.W. Sullivan hydro generating facility. In 2020, PGE had updated its ARO costs resulting in cumulative ARO expenses of $4 million being recognized. At the time PGE did not establish a regulatory asset, as probability of recovery in the depreciation study was not yet considered probable. Because the OPUC's order on the depreciation study includes recovery of the ARO, PGE established a regulatory asset and ARO balancing account, resulting in a credit to earnings of $4 million for the year ended December 31, 2021. For more information on PGE's AROs, see Critical Accounting Policies and Estimates in this Item 7., and see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Renewable Recovery Framework—As previously authorized by the OPUC, a primary method available to recover costs associated with renewable resources is the RAC. The RAC allows PGE to recover prudently incurred costs of renewable resources through filings made by April 1st each year. In the 2019 GRC Order, the OPUC authorized the inclusion of prudent costs of energy storage projects associated with renewables in future RAC filings to be made to the OPUC, under certain conditions. There have been no significant filings made under the RAC during 2021.

Operating Activities

In combination with electricity provided by PGE's own generation portfolio, to meet retail load requirements and balance energy supply with customer demand, the Company purchases and sells electricity in the wholesale market. The Company also performs portfolio management and wholesale market sales services for third parties in the region. PGE participates in the western EIM, which allows the Company to, among other things, integrate more renewable energy into the grid by better matching the variable output of renewable resources. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE also purchases natural gas in the United States and Canada to fuel its generation portfolio and sells excess gas back into the wholesale market.

The Company generates revenues and cash flows primarily from the sale and distribution of electricity to its retail customers. The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. Historically, PGE has experienced its highest MWa deliveries and retail energy sales during the winter heating season, although instances of peak deliveries have increased during the summer months, generally resulting from air conditioning demand. During the summer of 2021, demand reached a new all-time high, surpassing the previous mark, which was a winter peak. See *"Seasonality"* in the Customers and Revenues section in Item 1.—"Business." for further information regarding seasonal fluctuations. Retail customer price changes and customer usage patterns, which can be affected by the economy and recently, by changes due to COVID-19 restrictions, also have an effect on revenues. Wholesale power availability and price, hydro and wind generation, and fuel costs for thermal and gas plants can also affect income from operations.

Customers and Demand—The following tables present total energy deliveries and the average number of retail customers by customer type for 2021 and 2020.

Energy deliveries (MWh in thousands)	2021	2020	% Increase/ (Decrease)
Retail:			
Residential	7,978	7,756	2.9 %
Commercial (PGE sales only)	6,604	6,222	6.1
Direct Access	589	633	(7.0)
Total Commercial	7,193	6,855	4.9
Industrial (PGE sales only)	3,714	3,446	7.8
Direct Access	1,647	1,486	10.8
Total Industrial	5,361	4,932	8.7
Total (PGE sales only)	18,296	17,424	5.0
Total Direct Access	2,236	2,119	5.5
Total retail energy deliveries	20,532	19,543	5.1 %
Wholesale energy deliveries	5,946	5,794	2.6
Total energy deliveries	26,478	25,337	4.5 %

Average number of retail customers	2021		2020		% Increase/ (Decrease)
Residential	800,372	88 %	791,119	88 %	1.2 %
Commercial	111,062	12	110,290	12	0.7
Industrial	191	—	194	—	(1.5)
Direct access	584	—	634	—	(7.9)
Total	912,209	100 %	902,237	100 %	1.1 %

In 2021, retail energy deliveries increased 5.1% from 2020, with increases reflected in all three customer classes, as the region experienced a recovery from the COVID-19 downturn seen in 2020. Commercial and industrial classes experienced growth associated with economic recovery and, with COVID-19 variants continuing to impact consumer behavior, residential usage remained elevated.

In March 2020, the Governor of Oregon issued an order directing residents to stay at home except for essential activity and mandating closure of businesses for which close personal contact would be difficult or impossible to avoid. The Company saw a shift in retail demand in response, beginning with the second quarter of 2020. In particular, residential loads increased as a larger percentage of the population spent more time at home, whether working from home, providing child-care due to school closures, or lacking employment as commercial activity slowed. Conversely, commercial energy deliveries declined as many businesses were disrupted in an attempt to maintain social distancing or have closed as a result of the lack of business as residents followed directives from state and federal authorities. The majority of state and local mandates were lifted by mid-2021, allowing for commercial recovery to begin, however as COVID-19 variants impacted communities in 2021, impacts to energy deliveries, particularly increases in residential average usage remain.

Residential energy deliveries, which are most sensitive to fluctuations in temperatures, were 2.9% higher in 2021 than 2020, due to a 1.7% increase in average usage per customer, which resulted largely from warmer summer temperatures, and a 1.2% increase in the average number of customers. In 2021, the Company’s service territory experienced warmer temperatures during the cooling season than in 2020, indicating higher demand for cooling.

Commercial energy deliveries increased 4.9% overall with widespread increases across PGE’s customer base as many sectors impacted by COVID-19 related closures and economic conditions, including government and education, miscellaneous commercial, and lodging, began to recover.

Industrial energy deliveries increased 8.7% in 2021 due to continued strength in the high-tech manufacturing sector.

Total heating degree-days, an indication of electricity use for heating, in 2021 were 7% below the 15-year average although fairly consistent overall with total heating degree-days in 2020. Total cooling degree-days, a similar indication of the extent to which customers are likely to have used electricity for cooling, in 2021, exceeded the 15-year average by 52% and were 40% above the 2020 total. The following table presents the number of heating and cooling degree-days in 2021 and 2020, along with the current 15-year averages, reflecting the influence that weather had on comparative energy deliveries, most notably in the 2nd and 3rd quarters:

	Heating Degree-Days			Cooling Degree-Days		
	2021	2020	15-Year Average	2021	2020	15-Year Average
1st quarter	1,805	1,761	1,847	—	—	—
2nd quarter	498	554	629	238	99	93
3rd quarter	54	47	74	600	492	455
4th quarter	1,471	1,474	1,570	—	9	2
Total	3,828	3,836	4,120	838	600	550
Increase (decrease) from the 15-year average	(7)%	(7)%		52 %	9 %	

On a weather-adjusted basis, total retail deliveries increased 4.0% from 2020. The increase was driven by an 8.5% growth in industrial deliveries and 4.2% growth in commercial energy deliveries, in addition to a 1.0% increase in weather-adjusted deliveries to residential customers, which was driven by the growth in customer count. PGE expects retail energy deliveries for 2022 will continue to be impacted by COVID-19 related behavioral changes. PGE projects that retail energy deliveries for 2022 will be 2.0 to 2.5% above 2021 weather-adjusted levels, reflecting strength in industrial deliveries, and impacts associated with COVID-19 early in the year, and unwinding of such impacts later in the year.

ESSs supplied Direct Access customers with energy representing 11% of the Company's total retail energy deliveries during 2021 and 2020. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs represent 13% of the Company's total retail energy deliveries for 2021. With the adoption of the New Large Load Direct Access program in 2020, as much as 18% of the Company's 2021 energy deliveries could have been supplied by ESSs.

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

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

	Plant availability (1)		Actual energy provided compared to projected levels (2)		Actual energy provided as a percentage of total retail load	
	2021	2020	2021	2020	2021	2020
Thermal:						
Natural gas	89 %	92 %	114 %	74 %	48 %	43 %
Coal (3)	—	99	103	83	11	17
Wind	92	94	110	117	12	11
Hydro	83	86	73	71	6	7

(1) Plant availability represents the percentage of the year plants were available for operations, which is impacted by planned maintenance and forced, or unplanned, outages.

(2) Projected levels of energy are included as part of PGE's AUT. Such projections establish the power cost component of retail prices for the following calendar year. Any shortfall is generally replaced with power from higher cost sources, while any excess generally displaces power from higher cost sources.

(3) Plant availability excludes Colstrip, which PGE does not operate. Colstrip availability was 81% in 2021, compared with 74% in 2020. Boardman ceased coal-fired generation on October 15, 2020.

Energy received from PGE-owned and jointly-owned thermal plants in 2021 compared to 2020 remained materially consistent. In 2021, production at the Company's natural gas-fired plants increased to help meet retail load demands and offset a decrease in coal-fired generation as a result of Boardman ceasing operation in October 2020. Energy expected to be received from thermal resources is projected annually in the AUT based on forecast market prices, variable costs to run the plant, and the constraints of the plant. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year.

Total energy received from all hydroelectric sources, both PGE-owned generation and purchased, increased 14% in 2021 compared to 2020. Energy received from mid-Columbia and other regional hydroelectric projects increased 22% in 2021 due to new PPAs in place in 2021 as compared to 2020. The energy generated by the Company-owned facilities decreased 11% due to less favorable hydro conditions in 2021. Energy expected to be received from hydroelectric resources is projected annually in the AUT based on a modified hydro study, which utilizes 80 years of historical stream flow data. See *"Purchased power and fuel"* in the Results of Operations section in this Item 7, for further detail on regional hydro results.

Energy received from PGE-owned wind resources and under contracts increased 30% in 2021 compared to 2020 primarily due to the addition of Wheatridge during the fourth quarter of 2020 and more favorable wind conditions. Energy expected to be received from wind generating resources is projected annually in the AUT based on historical generation. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available.

Under the PCAM, PGE may share with customers a portion of cost variances associated with NVPC. Customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year, if such differences exceed a prescribed "deadband" limit, which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. The following is a summary of the results of the Company's PCAM as calculated for regulatory purposes for 2021 and 2020:

- For 2021, actual NVPC was above baseline NVPC by $62 million, which was outside the established deadband range. Pursuant to the PCAM, as PGE's preliminary regulatory ROE was below 8.5% pursuant to the related earnings test, as of December 31, 2021, PGE has deferred $29 million, which represents 90% of the excess variance expected to be collected from customers. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.
- For 2020, excluding certain trading losses totaling $127 million, for which PGE did not pursue recovery from customers, actual NVPC was below baseline NVPC by $13 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2020. A final determination regarding the 2020 PCAM results was made by the OPUC through a public filing and review in 2021, which confirmed no refund to customers pursuant to the PCAM for 2020. For further information regarding trading losses, see *"Actual NVPC"* in the Results of Operations section of this Item 7.

The AUT filing, which serves to reset the baseline NVPC for PCAM purposes, indicated that a $79 million increase was expected in 2021 over 2020. The 2022 AUT anticipates a $64 million increase in NVPC that will be recovered in customer prices beginning January 1, 2022.

Results of Operations

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

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

	Years Ended December 31,		% Increase (Decrease)
	2021 Amount	2020 Amount	
Total revenues	$ 2,396	$ 2,145	12 %
Operating expenses:			
Purchased power and fuel	822	708	16
Generation, transmission and distribution	310	293	6
Administrative and other	336	283	19
Depreciation and amortization	404	454	(11)
Taxes other than income taxes	146	138	6
Total operating expenses	2,018	1,876	8
Income from operations	378	269	41
Interest expense, net *	137	136	1
Other income:			
Allowance for equity funds used during construction	17	16	6
Miscellaneous income, net	9	6	50
Other income, net	26	22	18
Income before income taxes	267	155	72
Income tax expense	23	—	—
Net income	$ 244	$ 155	57 %

* Includes an allowance for borrowed funds used during construction of $8 million in both 2021 and 2020.

2021 Compared to 2020

Net income for 2021 increased $89 million from 2020. While customer growth continues, increases in revenues from retail energy deliveries and wholesale sales were largely offset by higher Purchased power and fuel expenses, particularly during the third quarter of 2021, after removing the impact of the previously reported energy trading losses of $127 million from the 2020 results. The Company benefited from the sale of excess natural gas back into the wholesale market, the addition of Wheatridge to the generation portfolio, and interest income on Regulatory Assets. Higher Administrative and general expenses reflect increases for employee wage and benefit expenses and outside services, including labor. Generation, transmission and distribution expenses increased largely from wildfire mitigation efforts, vegetation management, and storm restoration expenses.

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

	2021	2020	% Increase (Decrease)
Retail: (1)			
Residential	$ 1,118	$ 1,030	9 %
Commercial	690	616	12
Industrial	250	218	15
Direct Access	47	46	2
Subtotal	2,105	1,910	10
Alternative revenue programs, net of amortization	(29)	(6)	383
Other accrued revenues, net (2)	2	28	(93)
Total retail revenues	2,078	1,932	8
Wholesale revenues	255	162	57
Other operating revenues	63	51	24
Total revenues	$ 2,396	$ 2,145	12 %

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those customers that purchase their energy from ESSs. Commercial revenues from ESS customers were $18 million for 2021 and 2020. Industrial revenues from ESS customers were $29 million and $28 million for 2021 and 2020, respectively.

(2) Amount for the year ended December 31, 2020 is primarily comprised of $24 million of amortization, including interest, related to the net tax benefits due to the change in corporate tax rate under the TCJA.

Total retail revenues—The following items contributed to the increase in Total retail revenues for the year ended December 31, 2021 compared to the year ended December 31, 2020 (dollars in millions):

Year ended December 31, 2020	$ 1,932
Retail energy deliveries driven by higher industrial demand, the impact of COVID-19 resulting in higher residential demand, and the increase due to the effects of weather	94
Increase as a result of the AUT, approved by the OPUC, for higher anticipated power costs	67
Increase due to the RAC, as approved by the OPUC for Wheatridge placed into service	23
Alternative revenue programs related to the decoupling mechanism deferrals due to increased residential use per customer resulting from COVID-19	(7)
Combination of various supplemental tariffs and adjustments	(12)
Average price of energy deliveries due primarily to variation in usage among customer classes resulting from COVID-19	(19)
Year ended December 31, 2021	$ 2,078
Change in Total retail revenues	$ 146

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

In 2021, a $93 million, or 57%, increase from 2020 in wholesale revenues resulted from an $89 million increase from a 53% increase in average prices received when the Company sold power into the wholesale market and a $4 million increase related to a 3% increase in wholesale sales volume. Wholesale prices for electricity increased as a result of more extreme weather experienced during 2021 than was typical for the region, less hydro generation, and reduced regional capacity.

Other operating revenues increased $12 million, or 24%, in 2021 from 2020, primarily as a result of a $9 million increase due to market conditions that provided more revenue from the resale of natural gas back into the wholesale market in excess of amounts needed for the Company's generation portfolio. Natural gas prices were considerably higher in the first quarter of 2021 due in part to the impact of unusual weather events on the demand for natural gas.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts.

The following items contributed to the increase in Purchased power and fuel for the year ended December 31, 2021 compared to the year ended December 31, 2020 (dollars in millions, except for average variable power cost per MWh):

Year ended December 31, 2020	$	708
Average variable power cost per MWh		99
Total system load		44
PCAM deferral		(29)
Year ended December 31, 2021	$	822
Change in Purchased power and fuel	$	114
Average variable power cost per MWh:		
Year ended December 31, 2020	$	29.14
Year ended December 31, 2021	$	33.63
Total system load (MWh in thousands):		
Year ended December 31, 2020		24,286
Year ended December 31, 2021		25,295

For the year ended December 31, 2021, the $99 million increase related to the change in average variable power cost per MWh was primarily driven by a 20% increase in the average cost for purchased power due largely to purchases made at peak market prices to meet customer demand during the summer, partially offset by a 2% decrease in the average cost of power from the Company's own generation. The $43 million increase related to total system load was primarily due to a 9% increase in purchased power, driven largely by increased customer demand due to weather and load growth, as well as a 1% increase in the company's own generation.

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

	Years Ended December 31,			
	2021		2020	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Natural gas	9,306	37 %	8,029	33 %
Coal	2,060	8	3,232	13
Total thermal	11,366	45	11,261	46
Hydro	1,073	4	1,204	5
Wind	2,316	9	2,111	9
Total generation	14,755	58	14,576	60
Purchased power:				
Hydro*	4,789	19	3,936	16
Wind*	989	4	426	2
Solar*	501	2	414	2
Natural Gas	63	—	38	—
Waste, Wood and Landfill Gas*	167	1	174	1
Source not specified	4,031	16	4,722	19
Total purchased power	10,540	42	9,710	40
Total system load	25,295	100 %	24,286	100 %
Less: wholesale sales	(5,946)		(5,794)	
Retail load requirement	19,349		18,492	

*Includes power received from PURPA qualifying facilities of 15 MWh in 2021 and 17 MWh in 2020 from Hydro resources, 30 MWh in 2021 and 33 MWh in 2020 from Wind resources, 472 MWh in 2021 and 383 MWh in 2020 from Solar resources, and 102 MWh in 2021 and 93 MWh in 2020 from Waste, Wood and Landfill Gas resources.

The following table presents the forecasted April-to-September 2022 and actual April-to-September 2021 and 2020 runoff at particular points of major rivers relevant to PGE's hydro resources:

	Runoff as a Percent of Normal*		
Location	**2022 Forecast**	**2021 Actual**	**2020 Actual**
Columbia River at The Dalles, Oregon	105 %	82 %	104 %
Mid-Columbia River at Grand Coulee, Washington	108	89	109
Clackamas River at Estacada, Oregon	97	70	75
Deschutes River at Moody, Oregon	97	84	86

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

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, increased $21 million in 2021 compared with 2020. The increase attributable to changes in Purchased power and fuel expense was the result of a 15% increase in the average variable power cost per MWh and a 4% increase in total system load. The increase in actual NVPC was also a result of the 53% higher average price per MWh sold and a 3% increase in the volume of wholesale energy deliveries.

The following items contributed to the increase in Actual NVPC for the year ended December 31, 2021 compared to the year ended December 31, 2020 (in millions):

Year ended December 31, 2020	$	546
Purchased power and fuel expense		143
Wholesale revenues		(93)
PCAM Deferral		(29)
Year ended December 31, 2021		567
Change in NVPC	$	21

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

Energy Trading—PGE personnel entered into a number of energy trades during 2020, resulting in significant exposure to the Company. In August 2020, a portion of energy trading positions in PGE's energy portfolio experienced significant losses as wholesale electricity prices increased substantially at various market hubs due to extreme weather conditions, constraints to regional transmission facilities, and changes in power supply in the West. During this time period, the CAISO declared a Stage 3 Electrical Emergency and ordered the first rolling blackouts in the state of California since 2001. As a result of the convergence of these conditions, the Company's energy portfolio experienced realized losses of $127 million on these positions in 2020. PGE did not pursue recovery of the energy trading losses, and the increase in net variable power costs due to this trading activity was recognized in PGE's results of operations. PGE no longer has net market exposure from the energy trading positions that led to these losses.

Generation, transmission, and distribution

The following items contributed to the $17 million or 6% increase in Generation, transmission and distribution for the year ended December 31, 2021 compared to the year ended December 31, 2020 (in millions):

Year ended December 31, 2020	$	293
Decrease primarily due to lower maintenance expense as the result of reduced run hours and lower long-term service agreement costs at some of the Company's generation facilities		(20)
Higher storm restoration and wildfire risk mitigation expenses		19
Higher vegetation management and line maintenance expenses		8
Miscellaneous expenses		10
Year ended December 31, 2021		310
Change in Generation, transmission and distribution	$	17

PGE deferred $69 million of incremental costs for year ended December 31, 2021, related to February 2021 ice storm damage in PGE's service territory. See the "*Overview*" section of this Item 7., for more information.

Administrative and other

The following items contributed to the $53 million or 19% increase in Administrative and other for the year ended December 31, 2021 compared to the year ended December 31, 2020 (in millions):

Year ended December 31, 2020	$	283
Higher professional and contracted services		23
Wage and benefits expenses		20
Miscellaneous expenses		10
Year ended December 31, 2021		336
Change in Administrative and other	$	53

In 2021, PGE experienced higher Generation, transmission, and distribution and Administrative and other expenses due to inflation in labor and other operating expenses. The Company believes it is reasonably likely that this trend may continue in 2022 and could have a material impact on its results of operations. PGE's ongoing focus on cost management and operational efficiencies is expected to help mitigate inflation.

Depreciation and amortization

The following items contributed to the $50 million or 11% decrease in Depreciation and amortization for the year ended December 31, 2021 compared to year ended December 31, 2020 (in millions):

Year ended December 31, 2020	$	454
ARO revisions		(28)
Capital retirements, net of additions		(12)
Activity related to regulatory programs (offset elsewhere on the income statement)		(10)
Year ended December 31, 2021		404
Change in Depreciation and amortization	$	(50)

See *"Depreciation Study"* within "Regulatory Matters" in the Overview section of this Item 7., for more information regarding revisions made to non-utility AROs.

Taxes other than income taxes expense increased $8 million, or 6%, in 2021 compared with 2020, primarily due to higher Oregon property taxes and franchise fees.

Interest expense increased $1 million, or 1%, in 2021 compared with 2020 driven by higher average balances of outstanding debt.

Other income, net increased $4 million, or 18%, in 2021 compared to 2020, with the difference driven by higher regulatory interest income on deferred asset balances as well as higher AFUDC equity driven by higher construction work-in-progress balances in 2021.

Income tax expense increased $23 million in 2021 compared to 2020 primarily driven by higher pre-tax income. The increase was partially offset by a cumulative catch-up adjustment recorded in the first quarter of 2021 to defer and recognize a regulatory asset for previously recorded deferred income tax expenses on a certain local flow-through tax, as well as regulatory amortizations. See Note 12, Income Taxes, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements," for more information.

2020 Compared to 2019

For a comparison of the Company's results of operations for the fiscal year ended December 31, 2020 to the year ended December 31, 2019, see Item 7.—" Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual report on Form 10-K for the year ended December 31, 2020, filed with the SEC on February 19, 2021.

Liquidity and Capital Resources

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

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2021 and projected capital expenditures and future debt maturities for 2022 through 2026 (in millions, excluding AFUDC):

	Years Ending December 31,					
	2021	2022	2023	2024	2025	2026
Ongoing capital expenditures (1)	$ 620	$ 625	$ 650	$ 650	$ 650	$ 650
Integrated Operations Center	60	35	—	—	—	—
Total capital expenditures (2)	$ 680	$ 660	$ 650	$ 650	$ 650	$ 650
Long-term debt maturities	$ 160	$ —	$ —	$ 80	$ —	$ —

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects. Includes accrued capital additions, preliminary engineering, removal costs, and certain intangible working capital assets.

(2) Amounts subsequent to 2021 are estimates as of the date of this report and may be affected by economic conditions, including but not limited to, impacts of inflation, changes to the cost of materials and labor, and financing costs.

During 2021, PGE funded its capital expenditures through a combination of cash from operations in the amount of $532 million, and net proceeds from the issuance of FMBs in the total amount of $400 million. Capital expenditures in 2022 are expected to be $660 million. PGE plans to fund the 2022 capital expenditures with cash from operations during 2022, which is expected to range from $575 million to $625 million, the issuance of debt securities of up to $250 million, and the issuance of commercial paper, as needed. The actual timing and amount of any other issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures. For a discussion concerning PGE's ability to fund its future capital requirements, see "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Liquidity

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

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

	Years Ended December 31,	
	2021	2020
Cash and cash equivalents, beginning of year	$ 257	$ 30
Net cash provided by (used in):		
Operating activities	532	567
Investing activities	(656)	(787)
Financing activities	(81)	447
Net change in cash and cash equivalents	(205)	227
Cash and cash equivalents, end of year	$ 52	$ 257

2021 Compared to 2020

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The following items contributed to the net change in cash flows from operations for 2021 compared to 2020 (dollars in millions):

	Increase/ (Decrease)
Increase in Net income due primarily to energy trading losses in 2020	$ 89
Decrease in Depreciation and amortization due to retirements and ARO revisions in 2020	(50)
Increase related to Deferred income taxes	28
Change in Decoupling mechanism deferrals, net of amortization	23
Amortization of Tax Reform refunds in 2020 and not in 2021	23
Decrease related to Deferral of incremental storm costs	(67)
Decrease related to Deferral of incremental wildfire costs	(15)
Decrease as a result of changes in Accounts receivable and Unbilled revenue	(40)
Increase for Accounts payable primarily due to the timing of payments to vendors	35
Increase as a result of net Margin activity	21
Decrease due to changes in Other working capital	(38)
Other miscellaneous changes	(44)
Net change in cash flow from operations	**$ (35)**

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

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2022 will range from $420 million to $440 million. Combined with all other sources, cash provided by operations in 2022 is estimated to range from $575 million to $625 million.

Cash provided by operations includes the recovery in customer prices of cash charges related to various long-term contractual obligations such as interest on long-term debt and purchased power and fuel contracts. PGE’s anticipated employer contributions for its defined benefit pension plan and other postretirement plans is $3 million per year for the years ending 2022 through 2026. Contributions are expected to be covered by cash provided by operations. For additional information regarding contractual obligations, see Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $131 million decrease in net cash used in investing activities in 2021 compared with 2020 is primarily due to Wheatridge being constructed and placed in-service in 2020, partially offset by an increase in capital expenditures related to the IOC and winter storm restoration.

The Company plans for $660 million of capital expenditures in 2022 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. PGE plans to fund the 2022 capital expenditures with cash from operations during 2022, as discussed above, as well as with the issuance of long-term debt securities, and short-term debt as necessary. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2021, cash provided by financing activities consisted primarily of the issuance of $400 million of FMBs. In addition, the Company issued a $200 million short-term loan, made payments on short-term debt in the amount of $350 million, paid dividends in the amount of $150 million, and executed a $12 million common stock repurchase.

2020 Compared to 2019

For a comparison of liquidity and capital resources and the Company's cash flow activities for the fiscal year ended December 31, 2020 and 2019, see Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2020, which was filed with the SEC on February 19, 2021.

Credit Ratings and Debt Covenants

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

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

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

As of December 31, 2021, PGE had posted $55 million of collateral with these counterparties, consisting of $37 million in cash and $18 million in bank letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2021, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $62 million and decreases to $36 million by December 31, 2022. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is $129 million and decreases to $101 million by December 31, 2022 and $80 million by December 31, 2023.

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

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs. The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2021, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $799 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt to total capital ratio). As of December 31, 2021, the Company's debt to total capital ratio, as calculated under the credit agreements, was 55.9%.

Debt and Equity Financings

PGE's ability to secure sufficient short- and long-term capital at a reasonable cost is determined by its financial performance and outlook, its credit ratings, its capital expenditure requirements, alternatives available to investors, market conditions, and other factors, such as the volatility in the capital markets in response to COVID-19. Management believes that the availability of its revolving credit facility, the expected ability to issue short- and long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future.

Short-term Debt—Pursuant to an order issued by the FERC on January 20, 2022, PGE has authorization to issue short-term debt up to a total of $900 million through February 6, 2024. The following table shows available liquidity as of December 31, 2021 (in millions):

	December 31, 2021		
	Capacity	**Outstanding**	**Available**
Revolving credit facility [(1)]	$ 650	$ —	$ 650
Letters of credit [(2)]	220	79	141
Total credit	$ 870	$ 79	$ 791
Cash and cash equivalents			76
Total liquidity			$ 867

(1) Scheduled to expire September 2026.

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

On September 10, 2021, PGE amended and restated its existing revolving credit facility. As of December 31, 2021, PGE had a $650 million unsecured revolving credit facility scheduled to expire in September 2026. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% of the facility approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and to provide cash for general corporate purposes. PGE may borrow for one, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2021, PGE had no commercial paper outstanding.

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

Under the revolving credit facility, as of December 31, 2021, PGE had no borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2021, the aggregate unused available credit capacity under the revolving credit facility was $650 million.

In addition, PGE has three letter of credit facilities under which the Company has total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, which are considered off-balance sheet arrangements, letters of credit for a total of $79 million were outstanding as of December 31, 2021.

On March 31, 2021, PGE obtained an unsecured 364-day term loan in the aggregate principal amount of $200 million. The term loan bore interest for the relevant interest period at LIBOR plus 0.70%, with the interest rate subject to adjustment pursuant to the terms of the loan. The term loan was paid off on September 30, 2021 with proceeds from a FMB bond issuance.

Long-term Debt—During 2021, PGE issued a total of $400 million of FMBs, $150 million of which were issued under PGE's Green Financing Framework, which allows the Company to issue bonds and other debt instruments to finance or refinance eligible green projects.

On September 30, 2021, PGE issued $400 million in FMBs. The Bonds consist of:

- a series, due in 2028, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 1.82%;
- a series, due in 2031, in the amount of $50 million that will bear interest from its issuance date at an annual rate of 2.10%;
- a series, due in 2034, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 2.20%; and
- a series, due in 2051, in the amount of $150 million that will bear interest from its issuance date at an annual rate of 2.97%.

As of December 31, 2021, total long-term debt outstanding, net of $14 million of unamortized debt expense, was $3,285 million, none of which is scheduled to mature in 2022.

Capital Structure—PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including current debt maturities and excluding lease obligations) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade debt ratings and provides access to long-term capital at favorable interest rates. The Company's common equity ratio was 45.2% and 45.0% as of December 31, 2021 and 2020, respectively.

Critical Accounting Policies and Estimates

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

Regulatory Accounting

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

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

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

Asset Retirement Obligations

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

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

As a co-owner of Colstrip, PGE has provided surety bonds, which are considered off-balance sheet arrangements, of $23 million as of December 31, 2021 on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Station, Colstrip Montana (the AOC) as required by the Montana Department of Environmental Quality. It is possible that each co-owner of Colstrip will be required, at some future point, to post additional financial assurance to support further performance by the operator of closure and remediation actions under the AOC.

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

Contingencies

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

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

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

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

Energy Risk Management

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

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase and sale contracts to supplement its own generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase and sale of fuel for the Company's natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as: i) forward contracts, which may involve physical delivery of an energy commodity; ii) financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and iii) option contracts to mitigate risk that arises from market fluctuations of commodity prices. The Company does not intend to engage in trading activities for non-retail purposes.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2021 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2022	2023	2024	2025	2026	Thereafter	Total
Commodity contracts:							
Electricity	$ 20	$ 2	$ 3	$ 4	$ 5	$ 72	$ 106
Natural gas	(76)	(26)	(4)	—	—	—	(106)
Net unrealized (gain)/loss	$ (56)	$ (24)	$ (1)	$ 4	$ 5	$ 72	$ —

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

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

Foreign Currency Exchange Rate Risk

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

As of December 31, 2021, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2021, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper outstanding.

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

As of December 31, 2021, the total fair value and carrying amounts, excluding unamortized debt expense, by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date						
		Total	2022	2023	2024	2025	2026	There-after
First Mortgage Bonds	$ 3,708	$ 3,180	$ —	$ —	$ 80	$ —	$ —	$ 3,100
Pollution Control Revenue Bonds	123	119	—	—	—	—	—	119
Total	$ 3,831	$ 3,299	$ —	$ —	$ 80	$ —	$ —	$ 3,219

As of December 31, 2021, PGE had no long-term debt instruments subject to interest rate risk exposures.

Credit Risk

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

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, within certain limits currently in place due to the Company's response to COVID-19, as described in *"COVID-19 Impacts"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimates are used to provide an allowance for uncollectible accounts receivable related to retail sales to address such risk.

As of December 31, 2021, PGE's credit risk exposure is $173 million for commodity activities, of which $170 million is with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature from 2022 to 2025. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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

Report of Independent Registered Public Accounting Firm (PCAOB ID 34)	69
Consolidated Statements of Income for the years ended December 31, 2021, 2020, and 2019	72
Consolidated Statements of Comprehensive Income for the years ended December 31, 2021, 2020, and 2019	73
Consolidated Balance Sheets as of December 31, 2021 and 2020	74
Consolidated Statements of Shareholders' Equity for the years ended December 31, 2021, 2020, and 2019	76
Consolidated Statements of Cash Flows for the years ended December 31, 2021, 2020, and 2019	77
Notes to Consolidated Financial Statements	79

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matter

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

Regulatory Accounting - Refer to Notes 2 and 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Oregon (the OPUC), which has jurisdiction with respect to the rates for retail electricity in the state of Oregon. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as electric utility plant; regulatory assets and liabilities; operating revenues; operation and maintenance expense; income taxes; and depreciation expense.

The Company's rates for retail customers are determined and approved in regulatory proceedings based on an analysis of the Company's cost of providing service to retail customers. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

We identified the impact of rate regulation as a critical audit matter due to its pervasive impact on the Company's financial statements and the significant judgments made by management to support its assertions about impacted account balances and disclosures. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the OPUC, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

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

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a refund or future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances

recorded and regulatory developments.

- We read relevant regulatory orders issued by the OPUC for the Company, regulatory statutes, and other publicly available information to assess the likelihood of recovery in future rates or of a refund or future reduction in rates.
- For selected regulatory assets and liabilities, we evaluated whether management had determined such amounts in accordance with the regulatory orders.
- For selected regulatory assets that represented an accumulation of incurred costs, we performed substantive audit procedures by selecting individual items within the detail of selected regulatory assets and evaluated whether the selected items were probable of recovery based on existing regulatory orders or past precedent for similar items.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 16, 2022

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

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2021	**2020**	**2019**
Revenues:			
Revenues, net	$ 2,425	$ 2,151	$ 2,121
Alternative revenue programs, net of amortization	(29)	(6)	$ 2
Total Revenues	2,396	2,145	2,123
Operating expenses:			
Purchased power and fuel	822	708	614
Generation, transmission and distribution	310	293	323
Administrative and other	336	283	290
Depreciation and amortization	404	454	409
Taxes other than income taxes	146	138	134
Total operating expenses	2,018	1,876	1,770
Income from operations	378	269	353
Interest expense, net	137	136	128
Other income:			
Allowance for equity funds used during construction	17	16	10
Miscellaneous income (expense), net	9	6	6
Other income, net	26	22	16
Income before income taxes	267	155	241
Income tax expense	23	—	27
Net income	$ 244	$ 155	$ 214
Weighted-average shares outstanding (in thousands):			
Basic	89,481	89,485	89,353
Diluted	89,627	89,645	89,559
Earnings per share:			
Basic	$ 2.72	$ 1.73	$ 2.39
Diluted	$ 2.72	$ 1.72	$ 2.39

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2021	2020	2019
Net income	$ 244	$ 155	$ 214
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in 2021, $1 million in 2020, and an immaterial amount in 2019	1	(1)	(1)
Comprehensive income	$ 245	$ 154	$ 213

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2021	**2020**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 52	$ 257
Accounts receivable, net	329	271
Inventories, at average cost:		
Materials and supplies	51	49
Fuel	27	23
Regulatory assets—current	24	23
Other current assets	205	98
Total current assets	688	721
Electric utility plant:		
In service	11,838	10,974
Accumulated depreciation and amortization	(4,146)	(3,864)
In service, net	7,692	7,110
Construction work-in-progress	313	429
Electric utility plant, net	8,005	7,539
Regulatory assets—noncurrent	533	569
Nuclear decommissioning trust	47	45
Non-qualified benefit plan trust	45	42
Other noncurrent assets	176	153
Total assets	$ 9,494	$ 9,069

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31,	
	2021	2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 244	$ 153
Liabilities from price risk management activities—current	47	14
Short-term debt	—	150
Current portion of long-term debt	—	160
Current portion of finance lease obligations	20	16
Accrued expenses and other current liabilities	457	322
Total current liabilities	768	815
Long-term debt, net of current portion	3,285	2,886
Regulatory liabilities—noncurrent	1,360	1,369
Deferred income taxes	413	374
Unfunded status of pension and postretirement plans	206	299
Liabilities from price risk management activities—noncurrent	90	136
Asset retirement obligations	238	270
Non-qualified benefit plan liabilities	95	101
Finance lease obligations, net of current portion	273	129
Other noncurrent liabilities	59	77
Total liabilities	6,787	6,456
Commitments and contingencies (see notes)		
Shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 89,410,612 and 89,537,331 shares issued and outstanding as of December 31, 2021 and 2020, respectively	1,241	1,231
Accumulated other comprehensive loss	(10)	(11)
Retained earnings	1,476	1,393
Total shareholders' equity	2,707	2,613
Total liabilities and shareholders' equity	$ 9,494	$ 9,069

See accompanying notes to consolidated financial statements.

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

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balance as of December 31, 2018	89,267,959	$ 1,212	$ (7)	$ 1,301	$ 2,506
Shares issued pursuant to equity-based plans	119,165	1	—	—	1
Stock-based compensation	—	7	—	—	7
Dividends declared ($1.5175 per share)	—	—	—	(136)	(136)
Net income	—	—	—	214	214
Reclassification of stranded tax effects due to Tax Reform	—	—	(2)	2	—
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2019	89,387,124	1,220	(10)	1,381	2,591
Shares issued pursuant to equity-based plans	150,207	2	—	—	2
Stock-based compensation	—	9	—	—	9
Dividends declared ($1.5850 per share)	—	—	—	(143)	(143)
Net income	—	—	—	155	155
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2020	89,537,331	1,231	(11)	1,393	2,613
Shares issued pursuant to equity-based plans	123,281	—	—	—	—
Stock-based compensation	—	13	—	—	13
Repurchase of common stock	(250,000)	(3)	—	(9)	(12)
Dividends declared ($1.6975 per share)	—	—	—	(152)	(152)
Net income	—	—	—	244	244
Other comprehensive income	—	—	1	—	1
Balance as of December 31, 2021	89,410,612	$ 1,241	$ (10)	$ 1,476	$ 2,707

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2021	**2020**	**2019**
Cash flows from operating activities:			
Net income	$ 244	$ 155	$ 214
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	404	454	409
Deferred income taxes	5	(23)	6
Allowance for equity funds used during construction	(17)	(16)	(10)
Pension and other postretirement benefits	24	22	21
Decoupling mechanism deferrals, net of amortization	29	6	(2)
(Amortization) Deferral of net benefits due to Tax Reform	—	(23)	(23)
Stock-based compensation	14	11	9
Deferral of incremental storm costs	(67)	—	—
Deferral of incremental wildfire costs	(30)	(15)	—
Other non-cash income and expenses, net	(10)	23	34
Changes in working capital:			
(Increase) decrease in receivables and unbilled revenues	(64)	(24)	30
Decrease (increase) in margin deposits	(29)	8	—
Increase (decrease) in payables and accrued liabilities	61	26	(16)
Increase in margin deposits from wholesale counterparties	58	—	—
Other working capital items, net	(21)	17	(12)
Contribution to non-qualified employee benefit trust	(11)	(11)	(11)
Contribution to pension and other postretirement plans	(2)	(2)	(65)
Asset retirement obligation settlements	(18)	(18)	(9)
Other, net	(38)	(23)	(29)
Net cash provided by operating activities	532	567	546
Cash flows from investing activities:			
Capital expenditures	(636)	(784)	(606)
Purchases of nuclear decommissioning trust securities	(10)	(6)	(8)
Sales of nuclear decommissioning trust securities	12	9	13
Proceeds from sale of properties	4	—	—
Other, net	(26)	(6)	(3)
Net cash used in investing activities	(656)	(787)	(604)

See accompanying notes to consolidated financial statements.

Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 400	$ 549	$ 470
Payments on long-term debt	(160)	(98)	(350)
Debt extinguishment costs	—	(2)	(9)
Borrowings on short-term debt	200	275	—
Payments on short-term debt	(350)	(125)	—
Dividends paid	(150)	(140)	(134)

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

	Years Ended December 31,		
	2021	2020	2019
Repurchase of common stock	(12)	—	—
Other	(9)	(12)	(8)
Net cash provided by (used in) financing activities	(81)	447	(31)
Increase (decrease) in cash and cash equivalents	(205)	227	(89)
Cash and cash equivalents, beginning of year	257	30	119
Cash and cash equivalents, end of year	$ 52	$ 257	$ 30
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 120	$ 113	$ 116
Income taxes	16	17	33
Non-cash investing and financing activities:			
Accrued capital additions	87	72	76
Accrued dividends payable	40	38	36

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically-integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGE's corporate headquarters. The Company's corporate headquarters is located in Portland, Oregon and its approximately four thousand square mile, state-approved service area is located entirely within the state of Oregon. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2021, PGE served approximately 917 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2021, PGE had 2,839 employees in its workforce, with 678 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. The agreements cover 614 and 64 employees and expire March 2022 and August 2022, respectively. PGE also utilizes independent contractors and temporary personnel to supplement its workforce.

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

Consolidation Principles

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

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Reclassifications

To conform with current year presentation, the Company has reclassified Deferral of incremental wildfire costs of \$1 million from Other non-cash income and expenses, net and \$14 million from Other, net in the operating activities section of the consolidated statements of cash flows for the year ended December 31, 2020.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $44 million as of December 31, 2021 and $255 million as of December 31, 2020 included within Cash and cash equivalents in the consolidated balance sheets.

Accounts Receivable

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

Provisions for uncollectible accounts receivable and unbilled revenues related to retail sales are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates for credit losses are based on management's assessment of the current and forecasted probability of collection, aging of accounts receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for accounts receivable and unbilled revenues. For more information on PGE's provision for uncollectible accounts receivable and unbilled revenues see "*Accounts Receivable, Net"* in Note 4, Balance Sheet Components. A portion of PGE's provision for uncollectible accounts receivable and unbilled revenues is deferred as a regulatory asset, for more information see *"COVID-19 Impacts"* in Note 7, Regulatory Assets and Liabilities.

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of accounts receivable related to wholesale sales in 2021, 2020, or 2019.

Price Risk Management

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

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

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

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

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are included within Other current assets in the consolidated balance sheets and were $37 million as of December 31, 2021 and $8 million as of December 31, 2020. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheets and were $18 million and $12 million as of December 31, 2021 and 2020, respectively.

Inventories

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

Electric Utility Plant

Capitalization Policy

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

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction work-in-progress in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, PGE may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFUDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. On June 30, 2020 the FERC issued a waiver that provides that, for the 12-month period starting March 2020, jurisdictional utilities may apply an alternative AFUDC calculation formula that excludes the actual outstanding short-term debt balance and replaces it with the simple average of the actual 2019 short-term debt balance. The purpose of the waiver is to allow relief from the detrimental impacts of issuing short-term debt on the allowance for equity funds used during construction in response to COVID-19. PGE adopted the waiver in the second quarter of 2020. The FERC has subsequently extended the waiver through March 31, 2022.

AFUDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 6.7% in 2021, 6.9% in 2020, and 7.1% in 2019. AFUDC from borrowed funds, reflected as a reduction to Interest expense, net, was $8 million in 2021, $8 million in 2020, and $5 million in 2019. AFUDC from equity funds, included in Other income, net, was $17 million in 2021, $16 million in 2020, and $10 million in 2019.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.4% in 2021, 3.5% in 2020, and 3.6% in 2019. A component of depreciation expense includes estimated asset retirement removal costs allowed in customer prices.

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

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2030 to 2061. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	97
Wind	30
Transmission	58
Distribution	46
General	15

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to accumulated depreciation. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, if applicable, and included in Regulatory liabilities.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $446 million and $388 million as of December 31, 2021 and 2020, respectively, with amortization expense of $58 million in 2021 and $64 million in both 2020 and 2019. Future estimated amortization expense as of December 31, 2021 is as follows: $59 million in 2022; $51 million in 2023; $46 million in 2024; $33 million in 2025; and $25 million in 2026.

Marketable Securities

Nuclear decommissioning trust

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

Non-qualified benefit plan trust

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

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

Regulatory Accounting

Regulatory Assets and Liabilities

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

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

For additional information concerning the Company's regulatory assets and liabilities, see Note 7, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

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

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

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.5% for 2021, 2020, and 2019.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in PGE's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. For the year ended December 31, 2021, PGE's actual NVPC was $62 million above baseline NVPC, which is outside the established deadband range. Pursuant to the PCAM and related earnings test, as of December 31, 2021, PGE has deferred $29 million which represents 90% of the excess variance expected to be collected from customers. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings. For the year ended December 31, 2020, excluding certain trading losses totaling $127 million, for which PGE did not pursue recovery from customers, actual NVPC was below baseline NVPC by $13 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2020. A final determination regarding the 2020 PCAM results was made by the OPUC through a public filing and review in 2021, which confirmed no refund to customers pursuant to the PCAM for 2020.

The PCAM has resulted in no collection from, or refund to, customers since 2011.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's consolidated balance sheets. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques. The present value of estimated future decommissioning costs is capitalized and included in Electric utility plant, net on the consolidated balance sheets with a corresponding offset to ARO. For revisions to AROs in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

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

For additional information concerning the Company's AROs, see Note 8, Asset Retirement Obligations.

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's consolidated balance sheets. As of December 31, 2021, PGE had a net regulatory liability related to Utility plant AROs in the amount of $43 million and a net regulatory asset related to Trojan decommissioning ARO activities of $90 million. As of December 31, 2020, PGE had a net regulatory liability related to Utility plant AROs in the amount of $37 million and a net regulatory asset related to Trojan decommissioning ARO activities of $88 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 7, Regulatory Assets and Liabilities.

Contingencies

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

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

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

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

For additional information concerning the Company's contingencies, see Note 19, Contingencies.

Accumulated Other Comprehensive Loss

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

Revenue Recognition

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

Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $48 million in 2021, $46 million in 2020, and $45 million in 2019.

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

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

Alternative Revenue Programs

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

In the 2022 General Rate Case (2022 GRC), parties reached an agreement that would eliminate PGE's decoupling mechanism upon the effective date of new customer prices pursuant to the case, which are expected to begin in May 2022. Subject to approval by the OPUC, which is expected in a final order by April 2022, deferrals would cease, although amortization of previously recorded deferrals would continue as scheduled until collected or refunded in future customer prices.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For additional information concerning the Company's Stock-Based Compensation, see Note 14, Stock-Based Compensation Expense.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $208 million and $239 million as of December 31, 2021 and 2020, respectively, and will primarily be amortized using the average rate assumption method to account for the refund to customers as the temporary differences reverse.

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

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements of income.

NOTE 3: REVENUE RECOGNITION

Disaggregated Revenue

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

	Year Ended December 31,		
	2021	2020	2019
Retail:			
Residential	$ 1,118	$ 1,030	$ 981
Commercial	690	616	636
Industrial	250	218	196
Direct access customers	47	46	44
Subtotal	2,105	1,910	1,857
Alternative revenue programs, net of amortization	(29)	(6)	2
Other accrued (deferred) revenues, net (1)	2	28	22
Total retail revenues	2,078	1,932	1,881
Wholesale revenues (2)	255	162	170
Other operating revenues	63	51	72
Total revenues	$ 2,396	$ 2,145	$ 2,123

(1) Amounts for the year ended December 31, 2020 and 2019 is primarily comprised of $24 million and $23 million of amortization, respectively, including interest, related to the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA).
(2) Wholesale revenues include $63 million, $65 million, and $50 million related to physical electricity commodity contract derivative settlements for the years ended December 31, 2021, 2020, and 2019, respectively. Price risk management derivative activities are included within Total revenues but do not represent revenues from contracts with customers as defined by GAAP, pursuant to Topic 606. For further information, see Note 6, Risk Management.

Retail Revenues

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

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

Retail revenue is billed based on monthly meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that have not yet been billed to customers. This amount, classified as Unbilled revenues, which is included in Accounts receivable, net in the Company's consolidated balance sheets, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

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

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

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro, solar, and wind conditions, and daily and seasonal retail demand.

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

Other Operating Revenues

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

NOTE 4: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable, net includes $117 million and $97 million of unbilled revenues as of December 31, 2021 and 2020, respectively. Accounts receivable is net of an allowance for uncollectible accounts of $26 million as of December 31, 2021 and $16 million as of December 31, 2020. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2021	2020	2019
Balance as of beginning of year	$ 16	$ 5	$ 15
Increase in provision *	35	15	2
Amounts written off, less recoveries	(25)	(4)	(12)
Balance as of end of year	$ 26	$ 16	$ 5

* PGE has deferred as a regulatory asset $29 million and $8 million in bad debt expense pursuant to the OPUC's COVID-19 deferral order as of December 31, 2021 and December 31, 2020, respectively.

Other Current Assets and Accrued Expenses and Other Current Liabilities

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

	As of December 31,	
	2021	2020
Other current assets:		
Prepaid expenses	$ 66	$ 57
Margin deposits	37	8
Assets from price risk management activities	102	33
	$ 205	$ 98
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 106	$ 23
Accrued employee compensation and benefits	67	67
Accrued dividends payable	40	38
Accrued interest payable	29	29
Accrued taxes payable	46	36
Margin deposits from wholesale counterparties	58	—
Other	111	129
	$ 457	$ 322

Electric Utility Plant, Net

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

	As of December 31,	
	2021	2020
Electric utility plant:		
Generation	$ 4,649	$ 4,436
Transmission	1,012	970
Distribution	4,469	4,136
General	914	679
Intangible	794	753
Total in service	11,838	10,974
Accumulated depreciation and amortization	(4,146)	(3,864)
Total in service, net	7,692	7,110
Construction work-in-progress	313	429
Electric utility plant, net	$ 8,005	$ 7,539

NOTE 5: FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

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

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

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2021 and 2020, 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, 2021				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Cash equivalents	$ 44	$ —	$ —	$ —	$ 44
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	9	10	—	—	19
Corporate credit	—	14	—	—	14
Money market funds measured at NAV [2]	—	—	—	14	14
Non-qualified benefit plan trust: [3]					
Money market funds	1	—	—	—	1
Equity securities—domestic	4	—	—	—	4
Debt securities—domestic government	4	—	—	—	4
Price risk management activities: [1] [4]					
Electricity	—	16	1	—	17
Natural gas	—	115	5	—	120
	$ 62	$ 155	$ 6	$ 14	$ 237
Liabilities:					
Price risk management activities: [1] [4]					
Electricity	$ —	$ 33	$ 90	$ —	$ 123
Natural gas	—	13	1	—	14
	$ —	$ 46	$ 91	$ —	$ 137

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $36 million which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 6, Risk Management.

	December 31, 2020				
	Level 1	Level 2	Level 3	Other[(2)]	Total
Assets:					
Cash equivalents	$ 255	$ —	$ —	$ —	$ 255
Nuclear decommissioning trust: [(1)]					
Debt securities:					
Domestic government	9	11	—	—	20
Corporate credit	—	13	—	—	13
Money market funds measured at NAV [(2)]	—	—	—	12	12
Non-qualified benefit plan trust: [(3)]					
Money market funds	1	—	—	—	1
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: [(1) (4)]					
Electricity	—	4	4	—	8
Natural gas	—	36	1	—	37
	$ 273	$ 64	$ 5	$ 12	$ 354
Liabilities:					
Price risk management activities: [(1) (4)]					
Electricity	$ —	$ 5	$ 141	$ —	$ 146
Natural gas	—	4	1	—	5
	$ —	$ 9	$ 142	$ —	$ 151

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $33 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 6, Risk Management.

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

Assets held in the NDT and NQBP trusts are recorded at fair value in PGE's consolidated balance sheets and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

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

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

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

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

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

Assets and liabilities from price risk management activities, recorded at fair value in PGE's consolidated balance sheets, consist of derivative instruments entered into by the Company to manage its risk exposure to commodity price and foreign currency exchange rates and reduce volatility in NVPC. For additional information regarding these assets and liabilities, see Note 6, Risk Management.

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

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

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

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2021:							
Electricity physical forwards	$ —	$ 90	Discounted cash flow	Electricity forward price (per MWh)	$ 16.66	$129.75	$ 43.73
Natural gas financial swaps	5	1	Discounted cash flow	Natural gas forward price (per Dth)	2.02	8.02	2.81
Electricity financial futures	1	—	Discounted cash flow	Electricity forward price (per MWh)	26.76	68.43	52.46
	$ 6	$ 91					
As of December 31, 2020:							
Electricity physical forwards	$ —	$ 141	Discounted cash flow	Electricity forward price (per MWh)	$ 11.17	$ 51.18	$ 29.74
Natural gas financial swaps	1	1	Discounted cash flow	Natural gas forward price (per Dth)	1.52	4.33	2.29
Electricity financial futures	4	—	Discounted cash flow	Electricity forward price (per MWh)	8.78	58.42	43.71
	$ 5	$ 142					

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,	
	2021	2020
Net liabilities from price risk management activities as of beginning of year	$ 137	$ 97
Net realized and unrealized losses/(gains) *	(50)	38
Net transfers from Level 3 to Level 2	(2)	2
Net liabilities from price risk management activities as of end of year	$ 85	$ 137
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ (55)	$ 47

* Includes $5 million in net realized gains in 2021 and $9 million in 2020.

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. During the years ended December 31, 2021 and 2020, there were no transfers into Level 3 from Level 2. 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 from Level 3 at the end of the reporting period for all of its derivative instruments.

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

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

As of December 31, 2021, the carrying amount of PGE's long-term debt was $3,285 million, net of $14 million of unamortized debt expense, and its estimated aggregate fair value was $3,831 million. As of December 31, 2020, the carrying amount of PGE's long-term debt was $3,046 million, net of $13 million of unamortized debt expense, with an estimated aggregate fair value of $3,808 million.

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

NOTE 6: RISK MANAGEMENT

Price Risk Management

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

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the consolidated balance sheets, may include forward, future, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the consolidated statements of income. PGE also enters into non-exchange-traded weather contract options, which are accounted for using the intrinsic value method. 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,	
	2021	2020
Current assets:		
Commodity contracts:		
Electricity	$ 16	$ 4
Natural gas	86	29
Total current derivative assets[(1)]	102	33
Noncurrent assets:		
Commodity contracts:		
Electricity	1	4
Natural gas	34	8
Total noncurrent derivative assets[(1)]	35	12
Total derivative assets[(2)]	$ 137	$ 45
Current liabilities:		
Commodity contracts:		
Electricity	$ 36	$ 13
Natural gas	11	2
Total current derivative liabilities	47	15
Noncurrent liabilities:		
Commodity contracts:		
Electricity	87	133
Natural gas	3	3
Total noncurrent derivative liabilities	90	136
Total derivative liabilities[(2)]	$ 137	$ 151

(1) Total current derivative assets is included in Other current assets, and Total noncurrent derivative assets is included in Other noncurrent assets on the consolidated balance sheets.
(2) As of December 31, 2021 and 2020, no commodity derivative assets or liabilities were designated as hedging instruments.

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

	As of December 31,			
	2021		2020	
Commodity contracts:				
Electricity	4	MWh	6	MWh
Natural gas	181	Dth	137	Dth
Foreign currency contracts	$ 19	Canadian	$ 19	Canadian

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement at gross values on the consolidated balance sheet. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2021, gross amounts included as Price risk management liabilities subject to master netting agreements were $3 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2021, $1 million was for electricity and $2 million was for natural gas. As of December 31, 2020, gross amounts included as Price risk management liabilities subject to master netting agreements were $2 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2020, $1 million was for electricity and $1 million was for natural gas.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,		
	2021	2020	2019
Commodity contracts:			
Electricity	$ (38)	$ 160	$ 20
Natural Gas	(177)	(34)	(32)
Foreign currency contracts	—	(1)	(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $119 million, net losses of $12 million, and net gains of $2 million for the years ended December 31, 2021, 2020 and 2019, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2021 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2022	2023	2024	2025	2026	Thereafter	Total
Commodity contracts:							
Electricity	$ 20	$ 2	$ 3	$ 4	$ 5	$ 72	$ 106
Natural gas	(76)	(26)	(4)	—	—	—	(106)
Net unrealized (gain)/loss	$ (56)	$ (24)	$ (1)	$ 4	$ 5	$ 72	$ —

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, 2021 was $128 million, for which the Company has posted $38 million in collateral, consisting of $18 million of letters of credit and $20 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2021, the cash requirement to either post as collateral or settle the instruments immediately would have been $101 million. As of December 31, 2021, PGE had $14 million posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's consolidated balance sheet.

As of December 31, 2021, PGE received from counterparties $68 million in collateral, consisting of $10 million of letters of credit and $58 million of cash. Increases in collateral received from counterparties is due to the increase in PGE's derivative asset position. The obligation to return cash collateral held for derivative instruments is included in Accrued expenses and other current liabilities on the Company's consolidated balance sheets.

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

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 5, Fair Value of Financial Instruments.

NOTE 7: REGULATORY ASSETS AND LIABILITIES

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

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

		As of December 31,			
		2021			2020
	Remaining Amortization Period	Earning a Return (1)	Not Earning a Return	Total	Total
Regulatory assets:					
Price risk management	(2)	$ —	$ 55	$ 55	$ 124
Pension plan	(3)	—	131	131	240
Debt issuance costs	2049	—	23	23	25
Trojan decommissioning activities	2059	—	90	90	95
February 2021 ice storm and damage	(4)	67	—	67	—
Power cost adjustment mechanism	(5)	29	—	29	—
2020 Labor Day wildfire	(4)	45	—	45	15
COVID-19	(4)	36	—	36	10
Other	Various	58	23	81	83
Total regulatory assets		$ 235	$ 322	$ 557	$ 592
Regulatory liabilities:					
Asset retirement removal costs	(6)	$ 1,047	$ —	$ 1,047	$ 1,016
Deferred income taxes	(7)	208	—	208	239
Asset retirement obligations	(6)	43	—	43	37
Price risk management	(2)	—	55	55	18
Other	Various	57	56	113	82
Total regulatory liabilities		$ 1,355	$ 111	$ 1,466	$ 1,392

(1) Earning a return includes either interest on the regulatory asset or liability, or inclusion of the regulatory asset or liability as an increase or decrease to rate base at the allowed rate of return.

(2) No amortization period in accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains on derivative instruments until settlement.
(3) Recovery expected over the average service life of employees.
(4) Amortization period not yet determined.
(5) Amortization period not yet determined. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.
(6) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(7) Refund expected primarily through amortization using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 6, Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic pension and postretirement benefit costs. For further information, see Note 11, Employee Benefits.

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

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

February 2021 ice storm and damage represent the costs not previously included for recovery in customer prices related to major storm damage incurred during the twelve months ended December 31, 2021. Such costs were 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 on February 13, 2021. On February 15, 2021, the Company filed an application for authorization to defer emergency restoration costs for the February storms (Docket UM 2156). PGE does not expect an OPUC decision on the February storm deferral until 2022. While the Company believes the full amount of the deferral is probable of recovery as PGE's prudently incurred costs were in response to the unique and unprecedented nature of the storms, the OPUC has significant discretion in making the final determination of recovery and their conclusions of overall prudence, including an earnings review, and could result in a portion, or all, of PGE's deferral being disallowed for recovery.

Power Cost Adjustment Mechanism—As of December 31, 2021, actual NVPC was $62 million above baseline NVPC, and therefore PGE has deferred $29 million which represents 90% of the excess variance expected to be collected from customers. A final determination regarding the 2021 PCAM results will be made by the OPUC through a public filing and review in 2022. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings. For additional information on the PCAM, see "*Power Cost Adjustment Mechanism*" in Note 2, Summary of Significant Accounting Policies.

Wildfire—In 2020, Oregon experienced one of the most destructive wildfire seasons on record, with over one million acres of land burned that ultimately led Oregon's Governor to declare a state of emergency on August 20, 2020. As a result, PGE has incurred costs to replace and rebuild PGE facilities damaged by the fires, as well as addressing fire-damaged vegetation and other resulting debris and hazards both in and outside of PGE's property and right-of-way. Ongoing costs include replacing equipment, enhanced tree and brush clearing, and making emergency plans in close partnership with local, state, and federal land and emergency management agencies to further expand the use of a public safety power shutoff, if the need should arise. On October 20, 2020, the OPUC formally approved PGE's request for deferral of such costs (Docket UM 2115). As of December 31, 2021 and December 31, 2020, PGE's cumulative deferred costs related to the wildfire response was $45 million and $15 million, respectively. PGE continues to assess the damage to its infrastructure and expects regulatory recovery of prudently incurred restoration costs. PGE believes the full amount of the 2020 and 2021 deferrals are probable of recovery as the Company's prudently incurred costs were in response to the unique and unprecedented nature of the wildfire events leading to the deferral. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

COVID-19 Impacts—The COVID-19 pandemic led Oregon's Governor to declare a state of emergency on March 8, 2020 and is still in effect. Due to the adverse impacts of COVID-19 on economic activity, PGE has experienced an increase in bad debt expense, lost revenue, and other incremental costs. On March 20, 2020, PGE filed an application with the OPUC for deferral of certain incremental costs, such as bad debt expense, related to COVID-19. PGE, other utilities under the OPUC's jurisdiction, intervenors, and OPUC staff held discussions regarding the scope of costs incurred by utilities which may qualify for deferral under Docket UM2114, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers. The result of such discussions was an Energy Term Sheet (Term Sheet), which dictates costs in scope for deferral but is silent to the timing of recovery of such costs. On September 24, 2020, the Commission adopted a proposed OPUC Staff motion for Staff to execute stipulations incorporating the terms of the Term Sheet. PGE's deferral application was approved by the Commission on October 20, 2020 with final stipulations for the Term Sheet approved on November 3, 2020. As of December 31, 2021 and December 31, 2020, PGE's deferred balance was $36 million and $10 million, respectively, comprised primarily of bad debt expense in excess of what is currently considered and collected in customer prices. Amortization of any deferred costs will remain subject to OPUC review prior to amortization in customer prices and would be subject to an earnings test. PGE believes the full amount of the 2020 and 2021 deferrals is probable of recovery as the Company's prudently incurred costs were in response to the unique nature of the COVID-19 pandemic health emergency. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

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

Deferred income taxes represents income tax benefits primarily from property-related timing differences that will be refunded to customers when the temporary differences reverse. Substantially all of the amounts deferred are subject to tax normalization rules that require that the impact to the results of operations of amortizing the excess deferred income tax balance cannot occur more rapidly than over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 12, Income Taxes.

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

NOTE 8: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2021	2020
Trojan decommissioning activities	$ 139	$ 139
Utility plant	95	118
Non-utility property	35	34
Total asset retirement obligations	269	291
Less: current portion *	31	21
Noncurrent asset retirement obligations	$ 238	$ 270

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

Trojan decommissioning activities represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI will store the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2059. In 2021, the Company recorded accretion of $6 million and a reduction of $6 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 $5 million in 2021 for costs incurred in 2020 and $5 million in 2020 for costs incurred in 2019 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 2021, the Company recorded an overall decrease in utility AROs of $23 million, with the change comprised of reductions of $14 million due to revisions in estimated cash flows, accretion of $3 million, and a reduction of $12 million due to settled liabilities.

Non-utility property primarily represents AROs that have been recognized for portions of unregulated properties that are currently or previously leased to third parties. Revisions to estimates for non-utility AROs relate to assets that are no longer in service and the offset is charged directly to Depreciation and amortization on the consolidated statements of income in the period in which the revisions are probable and reasonably estimable. Non-utility AROs are not subject to regulatory deferral.

In 2020, PGE performed a decommissioning study to update its ARO liability which resulted in a $21 million increase to non-utility property AROs. As part of this study, the Company also established an ARO liability of $3 million related to utility hydro generating properties. In 2020, the ARO was charged to expense in the consolidated statement of income, as regulatory recovery was not yet considered probable. 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. The OPUC order includes cost recovery of $4 million related to the hydro generating properties. As such, PGE established a regulatory asset and ARO balancing account, resulting in a credit to Depreciation and amortization on the consolidated statements of income of $4 million in 2021.

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

	Years Ended December 31,		
	2021	2020	2019
Balance as of beginning of year	$ 291	$ 279	$ 197
Liabilities incurred	—	3	—
Liabilities settled	(18)	(18)	(9)
Accretion expense	10	10	9
Revisions in estimated cash flows	(14)	17	82
Balance as of end of year	$ 269	$ 291	$ 279

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

PGE maintains a separate Nuclear decommissioning trust in the consolidated balance sheet for funds collected from customers through prices to cover the cost of Trojan decommissioning activities.

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

NOTE 9: CREDIT FACILITIES

On September 10, 2021, PGE amended and restated its existing revolving credit facility. As of December 31, 2021, PGE had a $650 million revolving credit facility scheduled to expire in September 2026. The Company has the ability to expand the revolving credit facility to $750 million, if needed. Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, including as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on the Company's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2021, PGE was in compliance with this covenant with a 55.9% debt to total capital ratio. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. The Company believes these potential adjustments will have an immaterial impact on PGE's results of operations.

Under the revolving credit facility, as of December 31, 2021, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $650 million.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2021, PGE had no commercial paper outstanding.

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

In addition, PGE has three letter of credit facilities that provide a total capacity of $220 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 $79 million of letters of credit were outstanding as of December 31, 2021. Outstanding letters of credit are not reflected on the Company's consolidated balance sheets.

On April 9, 2020, PGE obtained a 364-day unsecured term loan from lenders in the aggregate principal amount of $150 million. The term loan bore interest for the relevant interest period at LIBOR plus 1.25%. The interest rate was subject to adjustment pursuant to the terms of the loan. On March 31, 2021, this term loan was repaid in full with proceeds from the subsequent term loan described below.

On March 31, 2021, PGE obtained an unsecured 364-day term loan in the aggregate principal amount of $200 million. The term loan bore interest for the relevant interest period at LIBOR plus 0.70%, with the interest rate subject to adjustment pursuant to terms of the loan. The credit agreement was set to expire on March 30, 2022, with any outstanding balance due and payable on such date. The term loan was paid off early on September 30, 2021 with proceeds from an FMB issuance.

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, 2024.

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

	Year Ended December 31,		
	2021	2020	2019
Average daily amount of short-term debt outstanding	$ 139	$ 131	$ 7
Weighted daily average interest rate *	0.9 %	1.5 %	2.6 %
Maximum amount outstanding during the year	$ 230	$ 225	$ 46

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

NOTE 10: LONG-TERM DEBT

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

	As of December 31,	
	2021	2020
First Mortgage Bonds, rates range from 1.82% to 6.88%, with a weighted average rate of 4.11%% in 2021 and 4.14% in 2020, due at various dates through 2051	$ 3,180	$ 2,940
Pollution Control Revenue Bonds, rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	3,299	3,059
Less: Unamortized debt expense	(14)	(13)
Less: Current portion of long-term debt	—	(160)
Long-term debt, net of current portion	$ 3,285	$ 2,886

First Mortgage Bonds—On January 6, 2021, the Company made a scheduled $140 million repayment of a 2.51% Series of First Mortgage Bonds with available cash.

On August 11, 2021, the Company made a scheduled $20 million repayment of a 9.31% Series of First Mortgage Bonds with available cash.

On September 30, 2021, PGE issued $400 million in FMBs. The Bonds consist of:

- a series, due in 2028, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 1.82%;
- a series, due in 2031, in the amount of $50 million that will bear interest from its issuance date at an annual rate of 2.10%;
- a series, due in 2034, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 2.20%; and
- a series, due in 2051, in the amount of $150 million that will bear interest from its issuance date at an annual rate of 2.97%.

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.

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

As of December 31, 2021, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2022	$ —
2023	—
2024	80
2025	—
2026	—
Thereafter	3,219
	$ 3,299

NOTE 11: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

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

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

As expected, PGE contributed no additional funds to the pension plan in both 2021 and 2020. PGE does not expect to contribute to the pension plan in 2022.

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 5, Fair Value of Financial Instruments.

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

Trust assets and plan liabilities related to the NQBP included in PGE’s consolidated balance sheets are as follows as of December 31 (in millions):

	2021			2020		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	$ 21	$ 24	$ 45	$ 19	$ 23	$ 42
Non-qualified benefit plan liabilities *	25	70	95	26	75	101

* For the NQBP, excludes the current portion of $2 million in 2021 and 2020, which are classified in Accrued expenses and other current liabilities in the consolidated balance sheets.

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

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

	As of December 31,			
	2021		2020	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	61 %	60 %	67 %	65 %
Debt securities	39	40	33	35
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	59 %	57 %	60 %	57 %
Debt securities	41	43	40	43
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	8 %	7 %	17 %	12 %
Debt securities	13	14	6	11
Insurance contracts	79	79	77	77
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, 2021:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 25	$ —	$ —	$ —	$ 25
Investments measured at NAV:					
Money market funds	—	—	—	6	6
Collective trust funds	—	—	—	764	764
Private equity funds	—	—	—	5	5
	$ 25	$ —	$ —	$ 775	$ 800
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	4	—	—	4
International	10	—	—	—	10
Debt securities—Domestic	—	6	—	—	6
Investments measured at NAV:					
Money market funds	—	—	—	6	6
Collective trust funds	—	—	—	8	8
	$ 13	$ 10	$ —	$ 14	$ 37
As of December 31, 2020:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 49	$ —	$ —	$ —	$ 49
Investments measured at NAV:					
Money market funds	—	—	—	6	6
Collective trust funds	—	—	—	692	692
Private equity funds	—	—	—	6	6
	$ 49	$ —	$ —	$ 704	$ 753
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$ —	$ —	$ —	$ 4
Equity securities:					
Domestic	—	3	—	—	3
International	9	—	—	—	9
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	9	9
	$ 13	$ 8	$ —	$ 14	$ 35

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

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 5, Fair Value of Financial Instruments. The following discussion provides information regarding the methods used in valuation of the various asset class investments held in the pension and other postretirement benefit plan trusts.

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

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

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

Collective trust funds—Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset back securities assets, are included in commingled trusts or separately managed accounts. The Company believes the redemption value of the collective trust funds are likely to be the fair value, which is represented by the net asset value as a practical expedient. 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, 2021 and 2020. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2021	2020	2021	2020	2021	2020
Benefit obligation:						
As of January 1	$ 1,010	$ 905	$ 76	$ 71	$ 28	$ 26
Service cost	19	17	2	2	—	—
Interest cost	27	31	2	2	1	1
Participants' contributions	—	—	—	—	—	—
Actuarial loss (gain)	(26)	104	(5)	4	—	3
Benefit payments	(47)	(44)	(5)	(4)	(2)	(2)
Administrative expenses	(3)	(3)	—	—	—	—
Plan amendment	(8)	—	1	1	—	—
Curtailment gain	—	—	—	—	—	—
As of December 31	$ 972	$ 1,010	$ 71	$ 76	$ 27	$ 28
Fair value of plan assets:						
As of January 1	$ 753	$ 695	$ 35	$ 34	$ 19	$ 17
Actual return on plan assets	97	105	4	2	1	1
Company contributions	—	—	3	3	3	3
Participants' contributions	—	—	—	—	—	—
Benefit payments	(47)	(44)	(5)	(4)	(2)	(2)
Administrative expenses	(3)	(3)	—	—	—	—
As of December 31	$ 800	$ 753	$ 37	$ 35	$ 21	$ 19
Unfunded position as of December 31	$ (172)	$ (257)	$ (34)	$ (41)	$ (6)	$ (9)
Accumulated benefit plan obligation as of December 31	$ 885	$ 907	N/A	N/A	$ 23	$ 24
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 21	$ 19
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(172)	(257)	(34)	(41)	(25)	(26)
Net liability	$ (172)	$ (257)	$ (34)	$ (41)	$ (6)	$ (9)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (78)	$ 43	$ (7)	$ 4	$ (1)	$ 3
Net prior service credit	(9)	1	—	—	—	—
Amortization of net actuarial loss	(22)	(17)	—	—	(1)	(1)
Amortization of prior service credit	—	—	1	1	—	—
	$ (109)	$ 27	$ (6)	$ 5	$ (2)	$ 2
Amounts included in AOCL:*						
Net actuarial loss (gain)	$ 139	$ 239	$ (3)	$ 5	$ 14	$ 15
Prior service cost	(8)	1	(7)	(8)	—	—
	$ 131	$ 240	$ (10)	$ (3)	$ 14	$ 15

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

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

- For the defined benefit pension plan, actuarial gains and losses due to demographic experience, including assumption changes, were a gain of $26 million and loss of $104 million, and the changes between actual and expected return on plan assets were gains of $52 million and $61 million for the years ended December 31, 2021 and 2020, respectively.
- For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were a gain of $5 million and loss of $5 million, and the changes between actual and expected return on plan assets were gains of $2 million and $1 million for each of the years ended December 31, 2021 and 2020, 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		
	2021	2020	2019	2021	2020	2019	2021	2020	2019
Service cost	$ 19	$ 17	$ 16	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	27	31	34	2	2	3	1	1	1
Expected return on plan assets	(45)	(44)	(40)	(2)	(2)	(2)	—	—	—
Amortization of prior service credit	—	—	—	(1)	(1)	—	—	—	—
Amortization of net actuarial loss	22	17	10	—	—	—	1	1	1
Curtailment gain	—	—	—	—	—	(2)	—	—	—
Net periodic benefit cost	$ 23	$ 21	$ 20	$ 1	$ 1	$ 1	$ 2	$ 2	$ 2

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

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

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2021	2020	2021	2020	2021	2020
Assumptions used to determine benefit obligations:						
Discount rate	2.92 %	2.64 %	2.75% - 3.11 %	2.22% - 2.92 %	2.92 %	2.64 %
Rate of compensation increase	4.26 %	3.65 %	4.13 %	4.58 %	4.10 %	4.10 %
Assumptions used to determine net periodic benefit cost:						
Discount rate	2.64 %	3.43 %	2.22% - 2.92 %	3.19% - 3.47 %	2.64 %	3.43 %
Rate of compensation increase	3.65 %	3.65 %	4.58 %	4.58 %	4.10 %	4.10 %
Long-term rate of return on plan assets	6.88 %	7.00 %	5.04 %	5.02 %	N/A	N/A

As of December 31, 2021, there are no liabilities with sensitivity to health care cost trend rates.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or a 0.25% reduction in the discount rate, would have the effect of increasing the 2021 net periodic pension expense by approximately $2 million and $3 million, respectively.

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

	Payments Due					
	2022	2023	2024	2025	2026	2027 - 2031
Defined benefit pension plan	$ 59	$ 59	$ 58	$ 57	$ 58	$ 277
Other postretirement benefits	5	5	6	6	5	19
Non-qualified benefit plans	2	3	2	2	2	11
Total	$ 66	$ 67	$ 66	$ 65	$ 65	$ 307

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

401(k) Retirement Savings Plan

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

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

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $26 million in 2021 and 2020, and $25 million in 2019.

NOTE 12: INCOME TAXES

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

	Years Ended December 31,		
	2021	2020	2019
Current:			
Federal	$ 4	$ 6	$ 9
State and local	14	17	12
	18	23	21
Deferred:			
Federal	—	(22)	(2)
State and local	5	(1)	8
	5	(23)	6
Income tax expense	$ 23	$ —	$ 27

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,		
	2021	2020	2019
Federal statutory tax rate	21.0 %	21.0 %	21.0 %
Federal tax credits (1)	(11.9)	(20.5)	(13.4)
State and local taxes, net of federal tax benefit (2)	8.9	10.1	6.5
Flow through depreciation and cost basis differences	(0.2)	(4.9)	1.5
Local tax flow-through adjustment	(3.2)	—	—
Amortization of excess deferred income tax (3)	(4.8)	(4.7)	(3.7)
Other	(1.2)	(1.0)	(0.7)
Effective tax rate	8.6 %	— %	11.2 %

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation ended or will end at various dates between 2017 and 2030.

(2) In 2019, Oregon enacted HB 3427, which imposed a new gross receipts tax on companies with annual revenues in excess of $1 million and applies to tax years beginning on or after January 1, 2020. The legislation defines that the tax applies to commercial activities sourced in Oregon, less certain deductions. The resulting amount is taxed at 0.57%.

(3) The majority of excess deferred income taxes related to remeasurement under the TCJA is subject to IRS normalization rules and will be amortized 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,	
	2021	2020
Deferred income tax assets:		
Employee benefits	$ 114	$ 136
Price risk management	—	29
Regulatory liabilities	39	23
Tax credits	98	77
Total deferred income tax assets	251	265
Deferred income tax liabilities:		
Depreciation and amortization	536	504
Regulatory assets	121	128
Other	7	7
Total deferred income tax liabilities	664	639
Deferred income tax liability, net	$ 413	$ 374

As of December 31, 2021, PGE has federal credit carryforwards of $98 million, consisting of PTCs, which will expire at various dates through 2041. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2021 and 2020 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2021, and 2020, PGE had no material unrecognized tax benefits.

PGE and its subsidiaries file a consolidated federal income tax return. The Company also files income tax returns in the states of Oregon, California, and Montana, and in certain local jurisdictions. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2010 and all issues were resolved related to those years. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

Local tax flow-through adjustment

The Company is subject to a local tax that is recovered through a supplemental tariff based on current tax expense, but for which the Company has also recognized deferred income tax expenses over time. Because it is probable that the local deferred taxes will be flowed through future customer prices in accordance with the supplemental tariff, PGE determined a corresponding regulatory asset should have been recorded. In the first quarter of 2021, PGE recognized a regulatory asset to defer previously recorded deferred income tax expenses in the amount of $9 million with a corresponding credit to Income tax expense reflected in the consolidated statements of income for the year ended December 31, 2021.

NOTE 13: EQUITY-BASED PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock or 1,500 shares (based on fair value on the purchase date), whichever is less. Two six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2021, there were 210,266 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, 2021, there were 2,459,827 shares available for future issuance pursuant to the DRIP.

NOTE 14: STOCK-BASED COMPENSATION EXPENSE

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

	Units	Weighted Average Grant Date Fair Value
Nonvested units of December 31, 2018	428,913	$ 38.43
Granted	210,555	49.06
Forfeited	(9,041)	41.68
Vested	(167,037)	37.52
Nonvested units as of December 31, 2019	463,390	43.52
Granted	202,883	56.45
Forfeited	(17,341)	50.27
Vested	(170,536)	45.67
Nonvested units as of December 31, 2020	478,396	48.00
Granted	318,844	43.01
Forfeited	(9,754)	48.35
Vested	(212,676)	40.33
Nonvested units as of December 31, 2021	574,810	48.07

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,439,300 shares remain available for future issuance as of December 31, 2021.

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

Time-based RSUs generally vest over a period of up to three years from the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was $3 million for the year ended December 31, 2021, and $1 million for both 2020 and 2019.

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 and Human Resources Committee of PGE's Board of Directors. The number of RSUs that may vest under the grants is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) average megawatts of forecast energy from clean or certain low-carbon emitting resources added to PGE's energy supply portfolio—and relative total shareholder return (TSR) as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 200% of the RSUs granted.

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

	2021	2020	2019
Risk-free interest rate	0.2 %	1.4 %	2.5 %
Expected term (in years)	2.9	2.9	3.0
Volatility	26.1 % - 37.9 %	13.5 % - 97.3 %	14.8 % - 74.5 %

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 166.5%, 133.2%, and 130.7% of awarded performance-based RSUs for the respective 2021, 2020, and 2019 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $7 million for the year ended December 31, 2021, $9 million for 2020, and $7 million for 2019.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $14 million for the year ended December 31, 2021, $11 million for 2020, and $9 million in 2019. Such amounts differ from those reported in the consolidated statements of shareholders' equity for stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and other expenses in the consolidated statements of income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to shareholders' equity of $1 million in 2021, and $2 million in 2020 and 2019.

As of December 31, 2021, unrecognized stock-based compensation expense was $14 million, which is expected to be recognized over a weighted average period of one to three years. No stock-based compensation costs have been capitalized.

NOTE 15: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; and ii) contingently issuable time-based and performance-based restricted stock units, along with associated DERs. Unvested performance-based restricted stock units and associated DERs are included in dilutive potential common shares only after the performance criteria have been met. Anti-dilutive stock awards are excluded from the calculation of diluted earnings per common share.

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

	Years Ended December 31,		
	2021	2020	2019
Weighted average common shares outstanding—basic	89,481	89,485	89,353
Dilutive potential common shares	146	160	206
Weighted average common shares outstanding—diluted	89,627	89,645	89,559

NOTE 16: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2021, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2022	2023	2024	2025	2026	Thereafter	Total
Capital and other purchase commitments	$ 146	$ 58	$ 7	$ 2	$ 1	$ 43	$ 257
Purchased power and fuel:							
Electricity purchases	486	353	367	341	242	2,284	4,073
Capacity contracts	18	22	23	27	12	88	190
Public utility districts	13	12	12	11	10	31	89
Natural gas	81	44	39	38	36	202	440
Coal and transportation	27	27	27	27	—	—	108
Total	$ 771	$ 516	$ 475	$ 446	$ 301	$ 2,648	$ 5,157

Capital and other purchase commitments—Certain commitments have been made for 2022 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase agreements with counterparties, which expire at varying dates through 2051, and power capacity contracts through 2040. Expenses associated with these commitments are recorded in purchased power and fuel on the Company's Consolidated Statements of Income.

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

- Grant County PUD for the Priest Rapids and Wanapum Hydroelectric Projects, and
- Douglas County PUD for the Wells Hydroelectric Project.

Under 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 the Douglas County agreement, the Company is required to make monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas County's loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

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

	Capacity Charges and Revenue Bonds as of December 31, 2021	PGE's Average Share as of December 31, 2021		Contract Expiration	Total PGE Contract Costs		
		Output	Capacity		2021	2020	2019
			(in MW)				
Priest Rapids and Wanapum	$ 1,976	8.6 %	163	2052	$ 26	$ 25	$ 21
Wells	496	17.6	105	2028	13	23	16

The agreements for Priest Rapids, Wanapum, and Wells 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 and transportation—The Company has a coal agreement with take-or-pay provisions related to Colstrip that expires in December 2025.

Guarantees

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2021, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 17: LEASES

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

Operating leases reflect lease expense on a straight-line basis, while finance leases result in the separate presentation of interest expense on the lease liability and amortization expense of the ROU asset. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

PGE does not record leases with a term of 12-months or less in the consolidated balance sheets. Total short-term lease costs as of December 31, 2021 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, and power purchase agreements that rely on identified plant. Variable payments are generally related to gas storage and power purchase agreements for components dependent upon variable factors, such as energy production and property taxes, and are not included in the determination of the present value of lease payments.

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

	2021	2020
Operating lease cost	$ 8	$ 8
Finance lease cost:		
Amortization of right-of-use assets	$ 7	$ 5
Interest on lease liabilities	11	10
Total finance lease cost	$ 18	$ 15
Variable lease cost	$ 24	$ 12

Supplemental information related to amounts and presentation of leases in the consolidated balance sheets is presented below (in millions):

	Balance Sheet Classification	December 31, 2021	December 31, 2020
Operating Leases:			
Operating lease right-of-use assets	Other noncurrent assets	$ 25	$ 44
Current liabilities	Accrued expenses and other current liabilities	$ 4	$ 8
Noncurrent liabilities	Other noncurrent liabilities	22	36
Total operating lease liabilities*		$ 26	$ 44
Finance Leases:			
Finance lease right-of-use assets	Electric utility plant, net	$ 291	$ 145
Current liabilities	Current portion of finance lease obligations	$ 20	$ 16
Noncurrent liabilities	Finance lease obligations, net of current portion	273	129
Total finance lease liabilities*		$ 293	$ 145

*Included in lease liabilities are $161 million and $25 million related to power purchase agreements for the years ended December 31, 2021 and 2020, respectively.

Lease term and discount rates were as follows:

	December 31, 2021	December 31, 2020
Weighted Average Remaining Lease Term (in years)		
Operating leases	40	26
Finance leases	23	28
Weighted Average Discount Rate		
Operating leases	3.8 %	3.6 %
Finance leases	5 %	7.3 %

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, 2021, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2022	$ 4	$ 20
2023	4	18
2024	3	18
2025	1	25
2026	1	25
Thereafter	43	377
Total lease payments	56	483
Less imputed interest	(30)	(190)
Total	$ 26	$ 293

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

	2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 8	$ 8	$ 7
Operating cash flows from finance leases	11	10	5
Financing cash flows from finance leases	6	6	$ 4
Right-of-use assets obtained in leasing arrangements:			
Operating leases	$ (12)	$ —	$ 56
Finance leases	153	—	154

In 2021, PGE entered into a hydroelectric power purchase agreement (PPA). The PPA modified an existing operating lease by effectively extending the term of the lease from 2024 to 2040 and increasing the capacity payments in the extension period. PGE reclassified the lease from operating to finance, and the Company recorded an additional lease liability and right-of-use (ROU) asset of approximately $141 million on PGE's consolidated balance sheets. The energy portion of the PPA is considered variable and will not be included in the calculation of the lease liability and right-of-use asset. Any material differences between expense recognition and timing of lease payments will be deferred as a regulatory asset or liability in order to match what is anticipated to be recovered in customer prices for ratemaking purposes.

As of December 31, 2021, PGE has an additional operating lease for an energy storage agreement that has not yet commenced with an estimated present value of future lease payments of $30 million. This lease is expected to commence in 2022 with a lease term of 20 years. Future estimated lease payments are $2 million annually from 2022 through 2026 and $32 million thereafter.

NOTE 18: JOINTLY-OWNED PLANT

As of December 31, 2021, 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	20.00 %	1986	$ 576	$ 399	$ 7
Pelton/Round Butte (2)	66.67 %	1958 / 1964	274	87	10
Total			$ 850	$ 486	$ 17

(1) Excludes AROs and accumulated asset retirement removal costs.
(2) For more information regarding changes to PGE's ownership share in the Pelton/Round Butte Project in 2022, see Note 20, Subsequent Events.

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

The Company operated, and continues to have a 90% ownership interest in Boardman, which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. As of December 31, 2021, PGE's ARO liability for its 90% share of the decommissioning costs was $23 million.

NOTE 19: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. 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.

Loss 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 an asset has been impaired, or a liability incurred, if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, 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.

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 the subsequent reporting period.

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

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

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

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

A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. With the completion of pre-remedial design sampling, Portland Harbor is now in the remedial design phase, which consists of additional technical information and data collection to be used to design the expected remedial actions. Certain PRPs, not including PGE, have entered into consent agreements to perform remedial design and the EPA has indicated it will take the initial lead to perform remedial design on the remaining areas. The Company anticipates that remedial design costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy. The EPA announced on February 12, 2021 that the entirety of Portland Harbor is under an active engineering design phase.

PGE continues to participate in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including conclusion of remedial design, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor. Based on the above facts and remaining uncertainties in the voluntary allocation process, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that represents 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 of Oregon, 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 (CTWS), 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. The Company believes that PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

The impact of costs related to EPA and NRD liabilities on the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) mechanism. As approved by the OPUC in 2017, the PHERA allows the Company to defer and recover incurred estimated liabilities and 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 general rate case. 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.

Securities Case

During September and October, 2020, three putative class action complaints were filed in U.S. District Court for the District of Oregon against PGE and certain of its officers, captioned *Hessel v. Portland General Electric Co.*, No. 20-cv-01523 (*"Hessel"*), *Cannataro v. Portland General Electric Co.*, No. 3:20-cv-01583 (*"Cannataro"*), and *Public Employees' Retirement System of Mississippi v. Portland General Electric Co.*, No. 20-cv-01786 (*"PERS of Mississippi"*). Two of these actions were filed on behalf of purported purchasers of PGE stock between April 24, 2020, and August 24, 2020; a third action was filed on behalf of purported purchasers of PGE stock between February 13, 2020, and August 24, 2020.

During the fourth quarter of 2020, the plaintiff in *Hessel* voluntarily dismissed his case and the Court consolidated *Cannataro* and *PERS of Mississippi* into a single case captioned *In re Portland General Electric Company Securities Litigation* (the "Securities Action") and appointed Public Employees' Retirement System of Mississippi lead plaintiff ("Lead Plaintiff"). On January 11, 2021, Lead Plaintiff filed an amended complaint asserting causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 for alleged misstatements and omissions regarding, among other things, PGE's alleged lack of sufficient internal controls and risks associated with PGE's trading activity in wholesale electric markets, purportedly on behalf of purchasers of PGE stock between February 13, 2020, and August 24, 2020 ("the Amended Complaint"). The Amended Complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees. On March 12, 2021, the defendants filed a motion to dismiss the Amended Complaint.

On July 11, 2021, the parties entered into a Stipulation of Settlement (the "Agreement") to fully resolve the Securities Action. The Agreement, which is subject to Court approval, provides for a settlement payment of $6.75 million in exchange for the complete dismissal with prejudice and a release of all claims against the defendants in connection with the Securities Action, without any admission of fault or wrongdoing by the defendants. On July 16, 2021, the Lead Plaintiff filed an application for Court approval of the settlement. In an order dated August 10, 2021, the Court granted preliminary approval of the settlement, stayed all proceedings in the action except with respect to settlement, and scheduled a final settlement approval hearing for March 11, 2022. The settlement payment was paid by the Company's insurance provider under its insurance policy. In light of the Agreement, the Court removed the hearing on the defendants' pending motion to dismiss from the calendar.

Putative Shareholder Derivative Lawsuits

On January 26, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned *Shimberg v. Pope*, No. 21- cv-02957, (the "*Shimberg* Action") against one current and one former PGE executive and certain members and former members of the Company's Board of Directors and naming the Company as a nominal defendant only. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company of not less than $10 million, equitable relief to remedy the alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs. On June 1, 2021, the plaintiff filed an unopposed motion to consolidate this lawsuit with the *Ashabraner* Action (described below), which the Court granted in an order dated July 27, 2021.

On March 17, 2021, a putative shareholder derivative lawsuit was filed in U.S. District Court for the District of Oregon, captioned *JS Halberstam Irrevocable Grantor Trust v. Davis*, No. 3:21-cv-00413-SI, (the "*JS Halberstam* Action") against one current and one former PGE executive and certain current and former members of the Company's Board of Directors. The plaintiff asserts claims for alleged breaches of fiduciary duties, waste of corporate assets, contribution and indemnification, aiding and abetting, and gross mismanagement, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks equitable relief to remedy and prevent future alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698 the "*Ashabraner* Action"), against one current and one former PGE executive and certain and former members of the Company's Board of Directors. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company, equitable relief, and an award of plaintiff's attorneys' fees and costs. On July 27, 2021, the Court issued an order consolidating the *Ashabrane*r Action with the *Shimberg* Action.

On May 21, 2021, a putative shareholder derivative lawsuit was filed in the U.S. District Court for the District of Oregon, Portland Division captioned *Berning v. Pope*, No. 3:21-cv-00783-SI, (the "*Berning* Action"; collectively with the *Shimberg, JS Halberstam*, and *Ashabraner* Actions, the "Derivative Actions"), against one current and one former PGE executive and certain current and former members of the Company's Board of Directors and naming the Company as a nominal defendant only. The plaintiff asserts claims for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff also asserts a claim against the two executives for contribution and indemnity based on alleged violations of Sections 10(b) and 21D of the Exchange Act. The complaint demands a jury trial and seeks multiple forms of relief, including, among other things: a declaration that defendants breached and/or aided and abetted the breach of their fiduciary duties to PGE; an order directing PGE to reform and improve its corporate governance and internal procedures; restitution; and an award of attorneys' fees, expenses, and costs.

On December 17, 2021, the parties to the Derivative Actions entered into a Memorandum of Understanding to settle the Derivative Actions subject to court approval and other terms (the "MOU"). After the parties entered into the MOU, the Court in the *Shimberg* and *Ashabraner* Actions granted an order to abate the proceedings until June 21, 2022. On December 17, 2021, the parties in the *JS Halberstam* Action filed a motion to stay the proceedings pending submission and court review of the settlement contemplated in the MOU.

On February 11, 2022, the parties to the Derivative Actions entered into a Stipulation of Settlement memorializing the terms of the non-monetary settlement, subject to Court approval, as set forth in the MOU. Under the Stipulation of Settlement, the parties to the *JS Halberstam* Action agree to stay the proceedings in the Derivative Actions pending Court approval of the settlement. In addition, the Stipulation of Settlement provides that defendants will not oppose or object to a request by plaintiffs' counsel for fees and expenses up to $750,000, which is subject to Court approval. Upon final approval of the Court, PGE expects such fees and expenses to be paid by the Company's insurance provider under its insurance policy. On February 15, 2022, the plaintiffs to the *JS Halberstam* Action filed a motion for preliminary approval of the settlement.

Governmental Investigations

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

Colstrip-Related Litigation

The Company has a 20% ownership interest in the Colstrip, which is operated by one of the co-owners, Talen Montana, LLC (Talen). Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. In addition, other parties have brought claims against the co-owners, which, along with the co-owner disagreements, are described below.

Petition to compel arbitration—On April 12, 2021, Avista Corporation, Puget Sound Energy Inc., PacifiCorp, and Portland General Electric Company (the Petitioners) petitioned in Spokane County Superior Court, Washington, Case No. 21201000-32, against NorthWestern Corporation (NorthWestern) and Talen to compel the arbitration initiated by NorthWestern to determine whether owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. On April 14, 2021, the Petitioners filed a petition to compel arbitration. On May 14, 2021, Talen removed the case to Federal Court (Eastern District of Washington Case No. 2:21-cv-00163-RMP). Petitioners filed a motion to remand on June 4, 2021, which was denied. Talen filed a motion, which, following a hearing in July 2021, was granted, to transfer the case to the U.S. District Court for the District of Montana.

Challenge to constitutionality of Montana Senate Bills 265 and 266 (SB 265 and SB 266)—On May 4, 2021, the Petitioners filed a claim against NorthWestern and Talen in U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00047-SPW-KLD, based on the passage of SB 265 in Montana, which attempts to void contractual provisions within the co-owner agreement for Colstrip if they do not provide for three arbitrators or provide for venue outside of the county where the plant is located. The passage of SB 265 was supported by Defendants and purports to void the O&O Agreement between all parties, which provides for one arbitrator and venue in Spokane, Washington. The petitioners allege that SB 265 violates the contracts clause of the U.S. Constitution and the Montana Constitution, and is preempted by the Federal Arbitration Act (FAA). The Petitioners seek declaratory relief that SB 265 is unconstitutional as applied to the O&O Agreement and the FAA preempts the enforcement of SB 265.

Petitioners filed a First Amended Complaint on May 19, 2021, adding the Attorney General of Montana (Montana AG) as defendant and challenging the constitutionality of Montana Senate Bill 266 (SB 266), which purportedly gives the Montana AG authority to penalize and restrain any co-owner of Colstrip who takes steps to shut-down the plant without unanimous consent, or otherwise fails to pay the costs to maintain the plant. Defendant Northwestern filed an answer on June 2, 2021 and asked that the case Talen filed, as described in the *"Complaint to implement SB 265 and SB 266"* below, and this case be consolidated. On May 27, 2021, Petitioners filed a Motion for Preliminary Injunction, to enjoin the Montana AG from enforcing SB 266 against them. On June 17, 2021, defendants NorthWestern and Talen filed their Oppositions to Motion for Preliminary Injunction (PI) and the Montana AG filed a response taking no position on the PI, stating the State of Montana does not envision enforcing SB 266 any time soon. The Court held a hearing on the Petitioners' Motion for PI August 6, 2021. On October 13, 2021, the Court issued an order that granted the Petitioners' Motion for PI, enjoining the Montana AG from enforcing SB 266 against them and on December 17, 2021, the Court further clarified its PI order.

On August 17, 2021, the Petitioners filed for partial summary judgment on their claim to declare unconstitutional or unenforceable SB 265, which purports to invalidate the arbitration provision of the parties' contract. Talen opposes the motion and Northwestern does not oppose the motion, but requests the Court compel arbitration. On October 29, 2021, the Petitioners filed a motion for summary judgment on their claim to declare unconstitutional and unenforceable SB 266. In November 2021, parties file responses, opposition, and a motion to stay action on the summary judgment. On December 3, 2021, NorthWestern moved to compel arbitration and to appoint a magistrate to oversee the arbitrator selection process. On December 23, 2021, Petitioners and Talen filed their responses. The Court set a status conference for February 15, 2022.

Complaint to implement SB 265 and SB 266—On May 4, 2021, Talen filed a complaint against the Petitioners and NorthWestern, in the Thirteenth Judicial District Court in the State of Montana, as an attempt to implement Montana laws when determining the language of the O&O agreement based on the recent enactment of SB 265, which purports to invalidate provisions of the co-owner operating agreement regarding arbitration, and SB 266, which purports to give the Montana AG authority to prosecute and levy a $100,000 a day fine against any co-owner who takes steps to close Colstrip without unanimous consent of all co-owners. The case was subsequently removed to the U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00058-SPW-TJC. Talen filed a motion to remand the case to the State of Montana District Court. Petitioners and NorthWestern have filed a motion to consolidate this case with the *Challenge to constitutionality of Montana Senate Bills 265 and 266,* described above. On October 21, 2022, the Court stayed the motion to consolidate pending the outcome of Talen's petition to remand.

On December 1, 2021, the U.S. Magistrate Judge issued Findings and Recommendations to remand the case back to state Court. On December 15, 2021, the Petitioners filed Objections to the Findings and Recommendation.

Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al. On December 14, 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. On August 26, 2021, the claim was amended to add PGE as a defendant. On November 1, 2021, the defendants filed an answer to the complaint. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court.

Since these lawsuits are in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible losses.

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 matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

NOTE 20: SUBSEQUENT EVENTS

Under terms of an agreement (the "Agreement") executed and approved by the OPUC in 2000, PGE has a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021. On June 30, 2021, the CTWS notified PGE of their intent to exercise this purchase option. Under the terms of the purchase option in the Agreement, on January 1, 2022, PGE completed the sale of the additional undivided interest in the project at a net book value of approximately $38 million, with no gain or loss recognized on the sale. 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 option is exercised, the CTWS' ownership percentage would exceed 50%. PGE remains the operator of the project.

PGE is obligated to purchase 100% of the CTWS' share of the project's output under a PPA through 2040. The exercise of the purchase option 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 being accounted for as a financing, and PGE will continue to record the asset on the consolidated balance sheets within Electric utility plant, net as if it were the legal owner and will continue to recognize depreciation expense over the estimated useful life. A financing obligation will be recorded in Other noncurrent liabilities. The monthly PPA payments will be split between interest expense and a reduction of the principal portion of the financing obligation. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

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

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

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

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company’s internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management’s assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2021, the Company’s internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2021, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company’s consolidated financial statements, as stated in their report included in Item 8.—“Financial Statements and Supplementary Data,” which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting, as of December 31, 2021.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2021 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

On February 16, 2022, the Company announced that, as part of an orderly succession process, Lisa Kaner, Vice President, General Counsel and Corporate Compliance Officer, will transition to Vice President, Corporate Compliance Officer, effective March 18, 2022, and plans to retire from PGE, effective July 1, 2022. The Company thanked Ms. Kaner for her leadership and many contributions as PGE's General Counsel and Corporate Compliance Officer for the last 5 years. The Company also announced the appointment of M. Angelica Espinosa as Vice President, General Counsel, effective March 18, 2022. Ms. Espinosa has served as Deputy General Counsel and Corporate Secretary of the Company since July 11, 2021. Prior to joining PGE, she held multiple roles at Southern California Gas Company (SoCalGas), a Sempra Energy regulated California utility, including Vice President of Gas Acquisition and Vice President and Chief Risk Officer of SoCalGas and San Diego Gas & Electric from January 1, 2019 to June 30, 2021. Prior to that, Ms. Espinosa served as Vice President of Compliance and Governance and Corporate Secretary for Sempra Energy and Chief Counsel for the Sempra International businesses from November 2014 to December 31, 2018. She joined Sempra Energy in 2014 from General Electric (GE), where she held multiple legal leadership positions including Regional Counsel for Latin America, Associate General Counsel for Commercial Operations in GE's Oil & Gas division and General Counsel for the Measurement and Control division of GE Oil & Gas. Ms. Espinosa earned her Juris Doctor, magna cum laude, and her Master of Law degrees from Southern Methodist University's Dedman School of Law. She also holds a law degree from Universidad de los Andes in Colombia.

In connection with this transition, Ms. Kaner will receive a special transition award of restricted stock units with a grant date fair value of $100,000, which will vest on July 1, 2022, subject to the terms of the equity award agreement.

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

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Certain information required by Item 10 is incorporated herein by reference to the relevant information under the captions “Corporate Governance” and “Item 1: Election of Directors” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the United States Securities and Exchange Commission (SEC) in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2022. Information regarding executive officers of Portland General Electric Company may be found in Part I, Item 1. Business of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions “Corporate Governance—Director Compensation,” “Corporate Governance—Compensation Committee Interlocks,” “Compensation and Human Resources Committee Report,” “Compensation Discussion and Analysis,” and “Executive Compensation Tables” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2022.

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

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions “Security Ownership of Certain Beneficial Owners, Directors and Executive Officers,” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2022.

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

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption “Corporate Governance” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2022.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions “Principal Accountant Fees and Services” and “Pre-Approval Policy for Independent Auditor Services” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2022.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

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

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1).
3.2*	Eleventh Amended and Restated Bylaws of Portland General Electric Company (Form 10-K filed February 15, 2019, Exhibit 3.2).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (Form 8-K filed August 3, 2017, Exhibit 4.1).
4.4*	Seventy-fifth Supplemental Indenture, dated April 1, 2019, between the Company and Wells Fargo Bank, National Association, as trustee (Form 8-K filed April 15, 2019, Exhibit 4.1).
4.5*	Description of Securities (Form 10-K filed February 15, 2019, Exhibit 4.6).
(10)	**Material Contracts**
10.1*	Second Amended and Restated Credit Agreement, dated as of September 10, 2021, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 8-K filed September 14, 2021, Exhibit 10.1). .
10.2*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.3*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.4*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.5*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.6*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +
10.7*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.8*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1) (File No. 001-05532-99). +
10.9*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1) (File No. 001-05532-99). +
10.10*	Form of Directors' Restricted Stock Unit Agreement (Form 10-K filed February 15, 2019, Exhibit 10.18).+

Exhibit Number	Description
10.11*	Portland General Electric Company Amended and Restated Incentive Compensation Clawback and Cancellation Policy. (Form 10-K filed February 19, 2021, Exhibit 10.19).+
10.12*	Portland General Electric Company Amended and Restated Severance Pay Plan for Executive Employees (the "Amended Plan"), effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.1).+
10.13*	Portland General Electric Company Annual Cash Incentive Plan as amended and restated effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.2).+
10.14*	Portland General Electric Company Stock Incentive Plan as amended and restated effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.3).+
10.15	Form of Officers' and Key Employees' Performance Stock Unit Agreement.+
10.16	Form of Officers' and Key Employees' Restricted Stock Unit Agreement.+
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(101)	**Interactive Data File**
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover page information from Portland General Electric Company's Annual Report on Form 10-K filed February 17, 2022, formatted in iXBRL (Inline Extensible Business Reporting Language).

* Incorporated by reference as indicated.

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

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

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

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 16, 2022.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ MARIA M. POPE

Maria M. Pope

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 16, 2022.

Signature	Title
/s/ MARIA M. POPE **Maria M. Pope**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JAMES A. AJELLO **James A. Ajello**	*Senior Vice President of Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ DAWN L. FARRELL **Dawn L. Farrell**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ MARIE OH HUBER **Marie Oh Huber**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*Director*
/s/ MICHAEL A. LEWIS **Michael A. Lewis**	*Director*
/s/ MICHAEL H. MILLEGAN **Michael H. Millegan**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ JAMES P. TORGERSON **James P. Torgerson**	*Director*

Corporate Information

Board Of Directors

Maria M. Pope
President and Chief Executive Officer,
Portland General Electric

Rodney L. Brown Jr.
Founding Partner,
Cascadia Law Group PLLC

Jack E. Davis
Chair of the Board of Directors,
Portland General Electric
Retired Chief Executive Officer,
Arizona Public Service Company

Kirby A. Dyess
Principal,
Austin Capital Management LLC

Dawn L. Farrell
Retired President and
Chief Executive Officer,
TransAlta Corporation

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

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

Kathryn J. Jackson
Senior Advisor,
Energy Impact Partners

Michael A. Lewis
Former Interim President,
Pacific Gas and Electric Company

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

Neil J. Nelson
Retired President,
Siltronic Corporation

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

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

Corporate Officers

Maria M. Pope
President and Chief Executive Officer

James A. Ajello
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

Larry N. Bekkedahl
Sr. Vice President,
Advanced Energy Delivery

Bradley Y. Jenkins
Vice President, Utility Operations

Lisa A. Kaner
Vice President, General Counsel
and Corporate Compliance Officer

John T. Kochavatr
Vice President,
Information Technology and
Chief Information Officer

John C. McFarland
Vice President,
Chief Customer Officer

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

W. David Robertson
Vice President, Public Policy

Brett M. Sims
Vice President, Strategy,
Regulation & Energy Supply

Investor Information

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

Transfer Agent
American Stock Transfer &
Trust Company LLC
6201 15th Ave.
Brooklyn, NY 11219
866-621-2788

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

Form 10-K
A copy of the Company's
2021 Annual Report on Form 10-K
will be furnished, without charge,
upon written request made to:
Jardon Jaramillo
Senior Director of Treasury, Investor
Relations and Risk Management
121 SW Salmon St.
1WTC0501
Portland, OR 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503-464-8586 or by downloading a copy from investors.portlandgeneral.com.

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

To vote online, visit investors.portlandgeneral.com.

Portland General Electric