

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2020/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q**GENERAL INFORMATION****I. Purpose**

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

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees 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 Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <https://forms.ferc.gov/>. The software is used to submit the electronic filing to the Commission via the Internet.

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

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

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

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____, we have also reviewed 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. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/overview>.

- (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/media/form-1> and <https://www.ferc.gov/media/form1-3q>.

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, submit the electronic filing using the form submission software only. 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.

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 be 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 salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

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

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

Document Accession #: 072004008026

File Date: 04/16/2021

IDENTIFICATION

01 Exact Legal Name of Respondent Portland General Electric Company		02 Year/Period of Report End of <u>2020/Q4</u>	
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 Christopher Liddle		06 Title of Contact Person 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 (503) 464-7458	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		10 Date of Report (Mo, Da, Yr) / /

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 James A. Ajello	03 Signature James A. Ajello	04 Date Signed (Mo, Da, Yr) 04/16/2021
02 Title SVP of Finance, CFO and 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.

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
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(a)(b)	Not applicable
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
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	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
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	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
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	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	Not applicable
66	Generating Plant Statistics Pages	410-411	

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LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input checked="" type="checkbox"/> Two copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent Document Accession #: 20210420-8046 Portland General Electric Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) //	Year/Period of Report End of <u>2020/Q4</u>
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GENERAL INFORMATION

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

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.

Oregon - Incorporated July 25, 1930

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.

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 natural 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...Enter the date when such independent accountant was initially engaged:
- (2) No

Name of Respondent Document Accession #: 20210420-8046 Portland General Electric Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2020/Q4</u>
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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has purchased the	100	
2		headquarters complex in		
3		Portland, Oregon and leases		
4		the complex to the Respondent		
5				
6	World Trade Center Northwest Corporation	Company is the holder of the	100	
7	(A wholly-owned subsidiary of 121 SW Salmon	World Trade Center Franchise		
8	Street Corporation)			
9				
10	Salmon Springs Hospitality Group	Company provides food	100	
11		catering services		
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OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Maria M. Pope	971,710
2			
3	Senior Vice President of Finance, Chief Financial Officer and Treasurer	James F. Lobdell	544,227
4			
5			
6	Vice President, General Counsel and Corporate Compliance Officer	Lisa A. Kaner	412,469
7			
8			
9	Vice President Strategy Regulation & Energy Supply	Brett Sims	297,822
10			
11	Vice President, Public Policy	W. David Robertson	348,211
12			
13	Vice President, Chief Customer Officer	John McFarland	317,225
14			
15	Vice President, Utility Operations	Bradley Y. Jenkins	388,153
16			
17	Vice President, Grid Architecture, Integration & Systems Operations	Larry N. Bekkedahl	390,608
18			
19			
20	Vice President, Information Technology and Chief Information Officer	John Kochavatr	377,601
21			
22			
23	Vice President, Operations Services	Kristin A. Stathis	333,185
24			
25	Vice President, Human Resources, Diversity, Equity & Inclusion	Anne E. Mersereau	352,187
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 1 Column: c

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

Schedule Page: 104 Line No.: 3 Column: b

Retired from company effective December 31, 2020.

Schedule Page: 104 Line No.: 9 Column: b

Appointed Vice President on October 30, 2020.

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), abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	John W. Ballantine	Palm Beach, Florida
2	Retired Executive Vice President, First Chicago NBD Corp.	
3		
4	Rodney L. Brown, Jr.	Seattle, Washington
5	Managing Partner, Cascadia Law Group PLLC	
6		
7	Jack E. Davis	Santa Fe, New Mexico
8	Chair of the Board, Portland General Electric	
9	Retired Chief Executive Officer, Arizona Public Service Co.	
10		
11	Kirby A. Dyess	Beaverton, Oregon
12	Principal, Austin Capital Management LLC	
13		
14	Mark B. Ganz	Portland, Oregon
15	Retired President and Chief Executive Officer,	
16	Cambia Health Solutions, Inc.	
17		
18	Kathryn J. Jackson	Cincinnati, Ohio
19	Director, Energy & Technology Consulting, KeySource, Inc.	
20		
21	Neil J. Nelson	Keizer, Oregon
22	Retired President and Chief Executive Officer,	
23	Siltronic Corp.	
24		
25	M. Lee Pelton	Boston, Massachusetts
26	President, Emerson College	
27		
28	Maria M. Pope	Portland, Oregon
29	President and Chief Executive Officer,	
30	Portland General Electric	
31		
32	Charles W. Shivery	Longboat Key, Florida
33	Retired President and Chief Executive Officer,	
34	Northeast Utilities	
35		
36	Marie Oh Huber	San Jose, California
37	Sr. VP, Chief Legal Officer, General Counsel	
38	and Secretary, eBay Inc	
39		
40	Michael H. Millegan	Kirkland, Washington
41	Founder and Chief Executive Officer,	
42	Millegan Advisory Group 3 LLC	
43		
44	Michael L. Lewis	Bethesda, Maryland
45	Retired Interim President of Pacific Gas and Electric Co.	
46		
47	James P. Torgerson	Brandford, Connecticut
48	Retired Chief Executive Officer, AVENGRID, Inc.	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 44 Column: a

Appointed to the Board effective January 1, 2021.

Schedule Page: 105 Line No.: 47 Column: a

Appointed to the Board effective January 1, 2021.

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? Yes
 No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

Yes
 No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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INFORMATION ON FORMULA RATES

Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent Portland General Electric Company Document Accession #: 20210420-8046	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report Filed Date: 04/16/2021	Year/Period of Report End of 2020/Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
 SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None
2. None
3. None
4. None
5. None

6. Pursuant to PGE's application, the FERC, on January 16, 2020, issued an order in Docket No. ES20-7-000 that authorizes the Company to issue up to \$900 million of short-term debt through February 7, 2022. 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.

As of December 31, 2020, PGE had a \$500 million revolving credit facility scheduled to expire in November 2023. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. 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 for general corporate purposes. PGE may borrow for one, two, 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 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, 2020, 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, 2020, PGE had no borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2020, the aggregate unused available credit capacity under the revolving credit facility was \$500 million.

In addition, PGE has four letter of credit facilities under which the Company has 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 \$60 million were outstanding, as of December 31, 2020.

On April 9, 2020, PGE obtained a 364-day term loan from lenders in the aggregate principal of \$150 million. The term loan bears interest for the relevant interest period at LIBOR plus 1.25%. The interest rate is subject to adjustment pursuant to the terms of the loan. The credit agreement is classified as Notes Payable on the Company's Comparative Balance Sheet and expires on April 8, 2021, with any outstanding balance due and payable on such date.

During 2020, PGE issued a total of \$430 million of First Mortgage Bond (FMBs).

On April 27, 2020, PGE issued \$200 million of 3.15% Series FMBs due in 2030.

On December 10, 2020, the Company issued to certain institutional buyers in the private placement market \$230 million aggregate principal amount of the Company's FMBs that consisted of:

- a series, due in 2027, in the amount of \$160 million that will bear interest from its issuance date at an annual rate of 1.84%; and
- a series, due in 2032, in the amount of \$70 million that will bear interest from its issuance date at an annual rate of 2.32%.

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Portland General Electric Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

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 are backed by the Company's Indenture of Mortgage by way of FMBs. Interest is payable semi-annually on the PCRBs.

As of December 31, 2020, total long-term debt outstanding was \$3,059 million, of which \$160 million is scheduled to mature in 2021.

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, 2020, 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:

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits seek damages totaling \$260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

In 2008, the OPUC issued an order (2008 Order) that required PGE to provide refunds, including interest, which refunds were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in 2013 and by the OSC in 2014.

In 2015, based on a motion filed by PGE, the Circuit Court lifted the abatement on the class action proceedings and, heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon.

In November 2019, the Court of Appeals issued an opinion that affirmed the Circuit Court dismissal. On December 30, 2019, the plaintiffs filed a motion for reconsideration, which the Court of Appeals denied on February 4, 2020.

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Portland General Electric Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

On April 7, 2020, the plaintiffs filed a petition with the OSC requesting review and reversal of the Court of Appeals opinion. On July 16, 2020, the OSC issued an order that denied the petition for review.

Deschutes River Alliance Clean Water Act Claims

In August 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company (Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon) that sought injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claimed PGE had violated certain conditions contained in PGE's Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleged the violations were related to PGE's operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam on the Deschutes River in central Oregon, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA has alleged that PGE's operation of the SWW has caused the above-referenced violations of the CWA, which in turn have degraded the fish and wildlife habitat of the Deschutes River below the Project and harmed the economic and personal interests of DRA's members and supporters.

In March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and the Confederated Tribes of Warm Springs (CTWS), which co-owns the Project, filed separate motions to dismiss. CTWS initially appeared as a friend of the court, but subsequently was found to be a necessary party to the lawsuit and joined as a defendant.

In August 2018, the U.S. District Court of the District of Oregon (District Court) denied DRA's motions for partial summary judgment and granted PGE's and CTWS's cross-motions for summary judgment, ruling in favor of PGE and CTWS. The District Court found that DRA had not shown a genuine dispute of material fact sufficient to support its contention that PGE and CTWS were operating the Project in violation of the CWA, and accordingly dismissed the case.

In October 2018, DRA filed an appeal and PGE and CTWS filed cross-appeals to the Ninth Circuit Court of Appeals. The appeals are fully briefed and oral argument is set for May 7, 2021.

The Company cannot predict the outcome of this matter or determine the likelihood of whether the outcome will result in a material loss.

Shareholder Lawsuits

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* 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 complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

The Company intends to vigorously defend against the lawsuit. Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

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, against one current and one former PGE executive and several members of the Company's Board of Directors (collectively, the "Individual Defendants") 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 Individual 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.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

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, against one current and one former PGE executive and all 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.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698, against one current and one former PGE executive and several 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.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

On October 28, 2020, the Board of Directors of the Company (the "Board") increased the size of the Board from twelve to fourteen directors and appointed Michael A. Lewis and James P. Torgerson to serve as directors of the Company, effective January 1, 2021. The Board appointed Mr. Lewis to serve on the Audit Committee and Finance Committee of the Board, and appointed Mr. Torgerson to serve on the Compensation and Human Resources Committee and Finance Committee of the Board, effective January 1, 2021.

On October 29, 2020, the Company announced that James F. Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer, plans to retire from Portland General Electric Company, effective December 31, 2020. The Company also announced the appointment of James. A. Ajello as senior advisor, effective November 30, 2020, and as Senior Vice President,

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Finance, Chief Financial Officer and Treasurer, effective January 1, 2021.

Brett Sims was appointed Vice President, Strategy, Regulation, and Energy Supply on October 30, 2020.

14. None

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)	200-201	11,014,910,106	11,146,578,388
3	Construction Work in Progress (107)	200-201	430,009,860	329,538,575
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,444,919,966	11,476,116,963
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,871,352,378	5,280,409,859
6	Net Utility Plant (Enter Total of line 4 less 5)		6,573,567,588	6,195,707,104
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,573,567,588	6,195,707,104
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		5,782,688	5,734,880
19	(Less) Accum. Prov. for Depr. and Amort. (122)		558,688	561,673
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	82,086,960	79,903,863
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		92,280,433	88,696,635
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		12,278,655	12,948,791
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		191,870,048	186,722,496
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,777,290	4,151,823
36	Special Deposits (132-134)		7,985,779	16,360,268
37	Working Fund (135)		5,000	5,000
38	Temporary Cash Investments (136)		255,000,000	26,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		161,079,488	147,888,136
41	Other Accounts Receivable (143)		27,683,325	23,110,998
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		15,642,244	4,476,885
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		809,120	32,372
45	Fuel Stock (151)	227	17,886,804	34,191,533
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	46,230,120	51,952,091
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	5,004,122	6,121,955

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	2,688,473	3,657,581
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		60,346,833	66,660,197
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		97,058,139	86,440,635
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		45,105,863	37,582,745
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		12,278,656	12,948,791
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		700,739,456	486,729,658
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		12,381,227	10,192,104
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	95,486,982	93,989,842
72	Other Regulatory Assets (182.3)	232	526,544,075	422,858,216
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,062,641	395,434
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		24,216	34,840
77	Temporary Facilities (185)		3	0
78	Miscellaneous Deferred Debits (186)	233	11,241,211	13,480,470
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		20,518,419	21,808,511
82	Accumulated Deferred Income Taxes (190)	234	617,639,369	563,329,261
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,284,898,143	1,126,088,678
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,751,075,235	7,995,247,936

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)	250-251	1,234,951,127	1,224,651,067
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	18,838,837	18,838,837
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	23,113,532	23,113,532
11	Retained Earnings (215, 215.1, 216)	118-119	1,388,159,313	1,378,134,934
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	4,547,299	2,364,202
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-11,105,713	-9,615,910
16	Total Proprietary Capital (lines 2 through 15)		2,612,277,331	2,591,259,598
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,058,800,000	2,607,800,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		378,658	441,860
24	Total Long-Term Debt (lines 18 through 23)		3,058,421,342	2,607,358,140
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		165,575,408	177,631,331
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		8,157,690	8,975,207
29	Accumulated Provision for Pensions and Benefits (228.3)		410,077,224	358,925,128
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		8,437,194	4,632,498
32	Long-Term Portion of Derivative Instrument Liabilities		136,458,836	107,979,023
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		291,070,650	279,375,319
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,019,777,002	937,518,506
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		150,000,000	0
38	Accounts Payable (232)		294,098,090	292,625,385
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		11,791,182	5,346,207
41	Customer Deposits (235)		15,247,123	14,654,130
42	Taxes Accrued (236)	262-263	26,689,924	15,472,177
43	Interest Accrued (237)		29,167,585	24,608,763
44	Dividends Declared (238)		37,932,372	35,789,096
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		15,729,568	17,441,259
48	Miscellaneous Current and Accrued Liabilities (242)		11,999,595	40,413,388
49	Obligations Under Capital Leases-Current (243)		24,192,962	24,869,839
50	Derivative Instrument Liabilities (244)		150,934,109	131,143,945
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		136,458,837	107,979,023
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		631,323,673	494,385,166
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	15,363,396	14,557,402
60	Other Regulatory Liabilities (254)	278	421,415,109	408,556,713
61	Unamortized Gain on Reaquired Debt (257)		18,117	26,169
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		819,161,947	800,256,070
64	Accum. Deferred Income Taxes-Other (283)		173,317,318	141,330,172
65	Total Deferred Credits (lines 56 through 64)		1,429,275,887	1,364,726,526
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,751,075,235	7,995,247,936

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,157,212,368	2,147,982,409		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,174,454,586	1,109,201,823		
5	Maintenance Expenses (402)	320-323	138,006,630	156,494,275		
6	Depreciation Expense (403)	336-337	315,333,112	307,699,071		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-3,966,273	6,887,698		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	64,345,245	64,406,427		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,751,548	-1,053,972		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		40,375,546	18,618,061		
13	(Less) Regulatory Credits (407.4)		793,489	76,383		
14	Taxes Other Than Income Taxes (408.1)	262-263	136,443,033	132,404,584		
15	Income Taxes - Federal (409.1)	262-263	7,732,855	8,919,648		
16	- Other (409.1)	262-263	17,587,387	11,992,123		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	236,124,396	249,989,313		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	255,226,529	244,396,828		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		4,274			
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		6,618,600	3,903,294		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,878,782,373	1,824,989,134		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		278,429,995	322,993,275		

STATEMENT OF INCOME FOR THE YEAR (Continued)

- 9. Use page 122 for important notes regarding the statement of income for any account thereof.
- 10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
- 11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
- 12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
- 13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
- 14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
- 15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
2,157,212,368	2,147,982,409					2
						3
1,174,454,586	1,109,201,823					4
138,006,630	156,494,275					5
315,333,112	307,699,071					6
-3,966,273	6,887,698					7
64,345,245	64,406,427					8
						9
1,751,548	-1,053,972					10
						11
40,375,546	18,618,061					12
793,489	76,383					13
136,443,033	132,404,584					14
7,732,855	8,919,648					15
17,587,387	11,992,123					16
236,124,396	249,989,313					17
255,226,529	244,396,828					18
						19
4,274						20
						21
						22
						23
6,618,600	3,903,294					24
1,878,782,373	1,824,989,134					25
278,429,995	322,993,275					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		278,429,995	322,993,275		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility 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)		3,253,422	2,090,267		
34	(Less) Expenses of Nonutility Operations (417.1)		3,290,215	1,937,113		
35	Nonoperating Rental Income (418)		7,573	-169,494		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	2,198,090	2,566,506		
37	Interest and Dividend Income (419)		519,241	1,091,115		
38	Allowance for Other Funds Used During Construction (419.1)		15,782,670	10,350,738		
39	Miscellaneous Nonoperating Income (421)		-18,114,548	2,840,629		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		356,233	16,832,648		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,244,403	2,423,809		
46	Life Insurance (426.2)		-4,267,563	-2,625,511		
47	Penalties (426.3)		115,667	132,974		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,219,135	1,199,586		
49	Other Deductions (426.5)		5,794,859	3,147,065		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,106,501	4,277,923		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	204,195	103,956		
53	Income Taxes-Federal (409.2)	262-263	-2,034,288	-1,209,756		
54	Income Taxes-Other (409.2)	262-263	-865,223	-512,454		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,616,606	2,116,948		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,773,681	788,473		
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)		-6,852,391	-289,779		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		2,102,123	12,844,504		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		123,508,651	118,738,532		
63	Amort. of Debt Disc. and Expense (428)		1,353,808	781,199		
64	Amortization of Loss on Reaquired Debt (428.1)		3,302,052	3,034,149		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		8,052	8,052		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		5,727,993	4,692,335		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,973,064	5,248,924		
70	Net Interest Charges (Total of lines 62 thru 69)		125,911,388	121,989,239		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		154,620,730	213,848,540		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		154,620,730	213,848,540		

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

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		1,374,282,139	1,297,494,166
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Reclassification of stranded tax effects due to Tax Reform			1,446,162
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			1,446,162
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		152,422,640	211,282,034
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-142,413,252	(136,140,223)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-142,413,252	(136,140,223)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		14,993	200,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,384,306,520	1,374,282,139
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

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)
41				
42				
43				
44				
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	3,852,795
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,793	3,852,795
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,388,159,313	1,378,134,934
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		2,364,202	(2,304)
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,198,090	2,566,506
51	(Less) Dividends Received (Debit)		14,993	200,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		4,547,299	2,364,202

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STATEMENT OF CASH FLOWS

(1) Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
 (2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
 (3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
 (4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction 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)	154,620,730	213,848,540
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	375,712,084	378,993,196
5	Amortization of Debt Discount	4,647,808	3,807,296
6	Amortization of Unrecovered Plant	1,751,548	-1,053,972
7	Net Price Risk Management Activities	12,267,046	-42,043,425
8	Deferred Income Taxes (Net)	-23,259,208	6,920,960
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-18,122,409	32,409,703
11	Net (Increase) Decrease in Inventory	24,113,641	-12,239,920
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	24,612,708	1,612,200
14	Net (Increase) Decrease in Other Regulatory Assets	-9,808,881	53,583,712
15	Net Increase (Decrease) in Other Regulatory Liabilities	-17,330,796	-19,571,074
16	(Less) Allowance for Other Funds Used During Construction	15,782,670	10,350,738
17	(Less) Undistributed Earnings from Subsidiary Companies	2,198,090	2,566,506
18	Other: Margin and Customer Deposits	8,967,482	2,045,734
19	Other: Operating	37,484,662	-62,058,994
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	557,675,655	543,336,712
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-795,174,628	-614,595,774
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-47,808	-69,378
30	(Less) Allowance for Other Funds Used During Construction	-15,782,670	-10,350,738
31	Other Capital Activities	-8,392,187	-1,066,616
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-787,831,953	-605,381,030
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Property		325,819
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	14,993	200,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
 (2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
 (3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
 (4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	451,607	-5,173,341
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	Purchases of Trojan Decommissioning Securities	-5,749,505	-8,488,330
54	Sales of Trojan Decommissioning Securities	8,773,036	13,113,169
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-784,341,822	-605,403,713
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	548,800,000	470,000,000
62	Preferred Stock		
63	Common Stock	-2,578,484	-2,270,471
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	150,000,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	696,221,516	467,729,529
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-97,800,000	-350,065,879
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-1,956,000	-8,766,000
77	Debt Issue Costs	-3,407,024	-1,863,172
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-139,766,858	-133,534,578
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	453,291,634	-26,500,100
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	226,625,467	-88,567,101
87			
88	Cash and Cash Equivalents at Beginning of Period	30,156,823	118,723,924
89			
90	Cash and Cash Equivalents at End of period	256,782,290	30,156,823

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FOOTNOTE DATA			

Schedule Page: 120 Line No.: 19 Column: b

Amounts relate primarily to decrease in prepayments and settlements of asset retirement obligations.

Schedule Page: 120 Line No.: 19 Column: c

Amount primarily consists of \$62 million of contributions to employee pension fund.

Schedule Page: 120 Line No.: 76 Column: b

Amount represents extinguishment costs of long term debt.

Schedule Page: 120 Line No.: 76 Column: c

Amount represents extinguishment costs of long term debt.

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NOTES TO FINANCIAL STATEMENTS

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

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

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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)	\$ 4,151,823	\$ 1,777,290
Working Funds (135)	5,000	5,000
Temporary Cash Investments (136)	26,000,000	255,000,000
	<u>\$ 30,156,823</u>	<u>\$ 256,782,290</u>
	2019	2020
Cash paid during the year:		
Interest	\$ 120,967,642	\$ 120,814,283
Allowance for borrowed funds used during construction	(5,248,924)	(7,973,064)
	<u>\$ 115,718,718</u>	<u>\$ 112,841,219</u>
Income Taxes	\$ 32,913,552	\$ 16,770,000
Non-cash investing and financing activities:		
Accrued capital additions	\$ 76,125,230	\$ 72,417,164
Accrued dividends payable	35,789,096	37,932,372
Assets obtained under leasing arrangements under ASC 842:		
Finance leases	153,811,914	—
Operating leases	56,460,807	—
Preliminary engineering transferred to Construction work in progress	1,667,673	28,433

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 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's corporate headquarters is located in Portland, Oregon and its approximately four thousand square

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2020, PGE served approximately 908 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2020, PGE had 3,639 members in its workforce (769 of which are contingent workers), with 721 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. The agreements cover 660 and 61 employees and expire March 2022 and August 2022, respectively.

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 Statements 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 Statements 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.

Reclassifications

To conform with current year presentation, the Company has reclassified Asset retirement obligation settlements of \$9 million from Other, net in the operating activities section of the Statement of Cash Flows for the year ended December 31, 2019.

Subsequent events

PGE has evaluated the impact of events occurring after December 31, 2020 up to February 18, 2021, the date that the Company's U.S.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 16, 2021. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

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 Temporary Cash Investments, of which PGE had \$255 million as of December 31, 2020 and \$26 million as of December 31, 2019 reflected in the Comparative Balance Sheet.

Customer Accounts Receivable

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

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

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

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

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

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are reflected as Special Deposits included within Current and Accrued

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Assets in the Comparative Balance Sheet and were \$8 million as of December 31, 2020 and \$16 million as of December 31, 2019. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were \$12 million and \$15 million as of December 31, 2020 and 2019, 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 (AFDC). 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 AFDC, 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 AFDC 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. AFDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 6.9% in 2020 and 7.1% in 2019. AFDC from borrowed funds, reflected as a reduction to Interest Charges, was \$8 million in 2020 and \$5 million in 2019. AFDC from equity funds, included in Other Income, was \$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 3.5% 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 2016 PGE completed a depreciation study based on 2015 data, with an order received from the OPUC in September 2017 authorizing new depreciation rates effective January 1, 2018. This study was incorporated into the Company's 2018 general rate case filed with the OPUC in 2017.

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the

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estimated retirement dates, which range from 2020 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	31
Transmission	58
Distribution	46
General	13

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 \$388 million and \$366 million as of December 31, 2020 and 2019, respectively, with amortization expense of \$64 million in both 2020 and 2019. Future estimated amortization expense as of December 31, 2020 is as follows: \$57 million in 2021; \$51 million in 2022; \$42 million in 2023; \$37 million in 2024; and \$25 million in 2025.

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 amounts collected from customers, 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 is based on the average cost method whereas cost of securities sold in the NQBP is 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.

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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 2020 and 2019.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating Revenues, net 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, 2020, PGE's actual NVPC was \$114 million above baseline NVPC. PGE excluded from actual NVPC and will not be pursuing regulatory recovery for amounts related to trading positions that resulted in realized losses of \$127 million during the third quarter of 2020. These losses were the result of a convergence of increased wholesale electricity prices at various market hubs due to extreme weather conditions, constraints to regional transmission facilities and changes in power supply in the West that occurred in August 2020. The Company no longer has net market exposure from these trading positions. After adjusting for the realized losses on the trading positions, PGE's actual NVPC for 2020 was \$13 million below baseline NVPC, which is within the established deadband range resulting in no estimated refund to customers.

A final determination of any customer refund or collection is made in the following year by the OPUC through a public filing and review. 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 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

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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, 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. As of December 31, 2019, PGE had a net regulatory liability related to Utility plant AROs in the amount of \$54 million and a net regulatory asset related to Trojan decommissioning ARO activities of \$91 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 6, Regulatory Assets and Liabilities.

Contingencies

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

A loss contingency will also be disclosed when it is reasonably possible that 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

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

Stock-Based Compensation

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

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. 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.

Recently Adopted Accounting Pronouncements

On January 1, 2020, PGE adopted ASU 2018-13 *Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement*. ASU 2018-13 amends Topic 820 to add, remove, and clarify disclosure requirements related to fair value measurement disclosures. As the standard relates only to disclosures, the implementation did not result in an impact to the results of operation, financial position or cash flows.

On January 1, 2020, PGE adopted ASU 2018-15 *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. ASU 2018-15 provides guidance on implementation costs incurred in a cloud computing arrangement that is a service contract and aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. For FERC reporting purposes, PGE plans to continue to capitalize such implementation costs to Utility Plant for material projects. PGE applied the amendments of this ASU prospectively, and the implementation did not have a material impact on PGE's results of

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operation, financial position or cash flows.

On January 1, 2020, PGE adopted ASU 2016-13 *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. ASU 2016-13 replaces the incurred loss impairment methodology in previous GAAP with a methodology that reflects expected credit losses, and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. PGE applied this ASU using a modified-retrospective approach, and as a result, amounts recorded prior to January 1, 2020 have not been retrospectively restated. Under the new standard, PGE estimates current expected credit losses for retail sales based on an 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 significant events that may impact the collectability of Customer Accounts Receivable and unbilled revenues. Provisions for current expected credit losses related to retail sales, and changes to the amount of expected credit losses for existing receivables, 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. The implementation did not have a material impact on PGE's results of operation, financial position, or cash flows.

On April 1, 2020, PGE adopted ASU 2020-04 *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*. ASU 2020-04 provides optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. PGE applied the amendments of this ASU prospectively, and the implementation did not have a material impact on PGE's results of operation, financial position, or cash flows.

PGE has adopted ASU 2018-14 *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*. ASU 2018-14 amends Topic 715 to add, remove, and clarify disclosure requirements related to defined benefit pension and other postretirement plans. As the standard relates only to disclosures, the adoption did not have a material impact on PGE's results of operation, financial position, or cash flows.

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,	
	2020	2019
Balance as of beginning of year	\$ 4	\$ 15
Increase in provision *	15	2
Amounts written off, less recoveries	(3)	(13)
Balance as of end of year	<u>\$ 16</u>	<u>\$ 4</u>

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

Net Utility Plant

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

	As of December 31,	
	2020	2019
Utility Plant:		

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Generation	\$	4,466	\$	4,954
Transmission		967		849
Distribution		4,137		3,917
General		683		661
Intangible		753		758
Total in service		11,006		11,139
Less: Accumulated Provision for Depreciation, Amortization, and Depletion		(4,871)		(5,280)
Total in service, net		6,135		5,859
Held for future use		9		7
Construction Work In Progress		430		330
Net Utility Plant	\$	6,574	\$	6,196

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 as of December 31, 2020 and 2019. The Company then classifies these financial assets and liabilities based on a fair value hierarchy that is 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, 2020 and 2019, 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):

As of December 31, 2020

	Level 1	Level 2	Level 3	Other⁽²⁾	Total
Assets:					

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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 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
	<u>\$ 273</u>	<u>\$ 64</u>	<u>\$ 5</u>	<u>\$ 12</u>	<u>\$ 354</u>
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	\$ —	\$ 5	\$ 141	\$ —	\$ 146
Natural gas	—	4	1	—	5
	<u>\$ —</u>	<u>\$ 9</u>	<u>\$ 142</u>	<u>\$ —</u>	<u>\$ 151</u>

- (1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities as appropriate.
- (2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
- (3) Excludes insurance policies of \$33 million, which are recorded at cash surrender value.
- (4) For further information regarding price risk management derivatives, see Note 5, Risk Management.

As of December 31, 2019

	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary Cash Investments	\$ 26	\$ —	\$ —	\$ —	\$ 26
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	8	16	—	—	24

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Corporate credit	—	9	—	—	9
Money market funds measured at NAV (2)	—	—	—	13	13
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	—	9	7	—	16
Natural gas	—	21	1	—	22
	<u>\$ 43</u>	<u>\$ 55</u>	<u>\$ 8</u>	<u>\$ 13</u>	<u>\$ 119</u>

Liabilities:

Price risk management activities: (1) (4)					
Electricity	\$ —	\$ 14	\$ 105	\$ —	\$ 119
Natural gas	—	12	—	—	12
	<u>\$ —</u>	<u>\$ 26</u>	<u>\$ 105</u>	<u>\$ —</u>	<u>\$ 131</u>

- (1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities as appropriate.
- (2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
- (3) Excludes insurance policies of \$29 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,

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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.

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

Commodity Contracts	Fair Value		Valuation Technique	Significant Unobservable Input	Price per Unit		
	Assets	Liabilities			Low	High	Weighted Average
(in millions)							
As of December 31, 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
	<u>\$ 5</u>	<u>\$ 142</u>					
As of December 31, 2019:							
Electricity physical forwards	\$ —	\$ 104	Discounted cash flow	Electricity forward price (per MWh)	\$ 12.53	\$ 59.00	\$ 36.92
Natural gas financial swaps	1	—	Discounted cash flow	Natural gas forward price (per Dth)	1.39	3.73	1.90
Electricity financial futures	7	1	Discounted cash flow	Electricity forward price (per MWh)	10.57	66.32	45.11
	<u>\$ 8</u>	<u>\$ 105</u>					

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

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

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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,	
	2020	2019
Net liabilities from price risk management activities as of beginning of year	\$ 97	\$ 88
Net realized and unrealized losses/(gains) *	38	10
Net transfers from Level 3 to Level 2	2	(1)
Net liabilities from price risk management activities as of end of year	\$ 137	\$ 97
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	\$ 47	\$ 16

* Includes \$9 million in net realized gains in 2020 and \$6 million in 2019.

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, 2020 and 2019, 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 FMBs and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2020, the carrying amount of PGE's long-term debt was \$3,059 million and its estimated aggregate fair value was \$3,808 million. As of December 31, 2019, the carrying amount of PGE's long-term debt was \$2,608 million with an estimated aggregate fair value of \$3,039 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

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dispatch decisions with respect to Company-owned generating resources. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, from which changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flows.

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

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

	As of December 31,	
	2020	2019
Current assets:		
Commodity contracts:		
Electricity	\$ 4	\$ 9
Natural gas	29	16
Total current derivative assets ⁽¹⁾	<u>33</u>	<u>25</u>
Noncurrent assets:		
Commodity contracts:		
Electricity	4	7
Natural gas	8	6
Total noncurrent derivative assets	<u>12</u>	<u>13</u>
Total derivative assets	<u>\$ 45</u>	<u>\$ 38</u>
Current liabilities:		
Commodity contracts:		
Electricity	\$ 13	\$ 14
Natural gas	2	9
Total current derivative liabilities	<u>15</u>	<u>23</u>
Noncurrent liabilities:		
Commodity contracts:		
Electricity	133	105
Natural gas	3	3
Total noncurrent derivative liabilities	<u>136</u>	<u>108</u>
Total derivative liabilities ⁽²⁾	<u>\$ 151</u>	<u>\$ 131</u>

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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,			
	2020		2019	
Commodity contracts:				
Electricity	6	MWh	6	MWh
Natural gas	137	Dth	145	Dth
Foreign currency contracts	\$ 19	Canadian	\$ 23	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, 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. As of December 31, 2019, PGE had no material gross master netting arrangements.

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,	
	2020	2019
Commodity contracts:		
Electricity	\$ 160	\$ 20
Natural Gas	(34)	(32)
Foreign currency contracts	(1)	(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net losses of \$12 million and net gains of \$2 million for the years ended December 31, 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, 2020 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2021	2022	2023	2024	2025	Thereafter	Total
Commodity contracts:							
Electricity	\$ 9	\$ 4	\$ 8	\$ 8	\$ 9	\$ 100	\$ 138
Natural gas	(27)	(5)	—	—	—	—	(32)
Net unrealized (gain)/loss	\$ (18)	\$ (1)	\$ 8	\$ 8	\$ 9	\$ 100	\$ 106

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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, 2020 was \$148 million, for which the Company has posted \$13 million in collateral, consisting of \$12 million of letters of credit and \$1 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2020, the cash requirement to either post as collateral or settle the instruments immediately would have been \$142 million. As of December 31, 2020, PGE had \$6 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.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities were as follows:

	As of December 31,	
	2020	2019
Assets from price risk management activities:		
Counterparty A	12 %	35 %
Counterparty B	17	13
Counterparty C	21	11
Counterparty D	16	11
	66 %	70 %
Liabilities from price risk management activities:		
Counterparty E	93 %	79 %

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,	
		2020	2019
Regulatory assets:			
Price risk management	2035	\$ 124	\$ 95
Pension plan	(1)	240	213
Deferred income taxes	(3)	\$ 56	45

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Other	Various	107	70
Total regulatory assets		<u>\$ 527</u>	<u>\$ 423</u>
Regulatory liabilities:			
Deferred income taxes	(3)	295	304
Asset retirement obligations	(2)	37	54
Price risk management	2021	18	1
Other	Various	71	50
Total regulatory liabilities		<u>\$ 421</u>	<u>\$ 409</u>

(1) Recovery expected over the average service life of employees.

(2) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.

(3) 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.

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,	
	2020	2019
Trojan decommissioning activities	\$ 139	\$ 137
Utility plant	118	126
Non-utility property	34	16
Total asset retirement obligations	<u>\$ 291</u>	<u>\$ 279</u>

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

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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. The Company recorded accretion of \$6 million and a reduction of \$4 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 2020 for costs incurred in 2019 and \$4 million in 2019 for costs incurred in 2018 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 governed by environmental regulation. During 2020, the Company recorded an overall decrease in utility AROs of \$8 million, with the change comprised of new liabilities incurred of \$5 million, reduction of \$4 million due to revisions in estimated cash flows, accretion of \$4 million, and a reduction of \$13 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 estimate. 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 properties and was charged to expense in the Statement of Income. PGE plans to pursue regulatory recovery for the utility portion of the ARO update, however as of December 31, 2020 no amounts have been deferred as a regulatory asset.

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

	Years Ended December 31,	
	2020	2019
Balance as of beginning of year	\$ 279	\$ 197
Liabilities incurred	3	—
Liabilities settled	(18)	(9)
Accretion expense	10	9
Revisions in estimated cash flows	17	82
Balance as of end of year	<u>\$ 291</u>	<u>\$ 279</u>

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 trust account, 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 asset retirement removal costs, which is included in Regulatory liabilities on PGE's Comparative Balance Sheet.

NOTE 8: CREDIT FACILITIES

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As of December 31, 2020, PGE had a \$500 million revolving credit facility scheduled to expire in November 2023. The Company has the ability to expand the revolving credit facility to \$600 million, if needed. The credit facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% approve the extension request.

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, two, 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 PGE'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, 2020, PGE was in compliance with this covenant with a 56.4% debt to total capital ratio.

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

Under the revolving credit facility, as of December 31, 2020, 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 \$500 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, 2020, PGE had no commercial paper outstanding.

In addition, PGE has four 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 \$60 million of letters of credit were outstanding as of December 31, 2020. 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 of \$150 million. The term loan bears interest for the relevant interest period at LIBOR plus 1.25%. The interest rate is subject to adjustment pursuant to the terms of the loan. The credit agreement is classified as Notes Payable on the Company's Comparative Balance Sheet and expires on April 8, 2021, with any outstanding balance due and payable on such date.

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, 2022.

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

	Year Ended December 31,	
	2020	2019
Average daily amount of short-term debt outstanding	\$ 131	\$ 7
Weighted daily average interest rate *	1.5 %	2.6 %
Maximum amount outstanding during the year	\$ 225	\$ 46

* 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):

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	As of December 31,	
	2020	2019
First Mortgage Bonds , rates range from 1.84% to 9.31%, with a weighted average rate of 4.14% in 2020 and 4.63% in 2019, due at various dates through 2050	\$ 2,940	\$ 2,510
Pollution Control Revenue Bonds , rates at 2.13% and 2.38%, due 2033	119	119
Pollution Control Revenue Bonds held by PGE	—	(21)
Total long-term debt	\$ 3,059	\$ 2,608

First Mortgage Bonds—On April 27, 2020, PGE issued \$200 million of 3.15% Series FMBs due in 2030.

On December 10, 2020, PGE issued \$230 million aggregate principal amount of the Company's FMBs that consisted of:

- 1 a series, due in 2027, in the amount of \$160 million that will bear interest from its issuance date at an annual rate of 1.84%; and
- 2 a series, due in 2032, in the amount of \$70 million that will bear interest from its issuance date at an annual rate of 2.32%.

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, 2020, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:

2021	\$	160
2022		—
2023		—
2024		80
2025		—
Thereafter		2,819
	\$	3,059

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

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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 2020 after contributing \$62 million in 2019. PGE does not expect to contribute to the pension plan in 2021.

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 unfunded Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide 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):

	2020			2019		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	\$ 19	\$ 23	\$ 42	\$ 17	\$ 21	\$ 38
Non-qualified benefit plan liabilities	28	75	103	26	79	105

Investment Policy and Asset Allocation—The Board of Directors of PGE 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,			
2020		2019	
Actual	Target *	Actual	Target *

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Defined Benefit Pension Plan:

Equity securities	67 %	65 %	64 %	65 %
Debt securities	33	35	36	35
Total	100 %	100 %	100 %	100 %

Other Postretirement Benefit Plans:

Equity securities	60 %	57 %	61 %	59 %
Debt securities	40	43	39	41
Total	100 %	100 %	100 %	100 %

Non-Qualified Benefits Plans:

Equity securities	17 %	12 %	17 %	12 %
Debt securities	6	11	7	12
Insurance contracts	77	77	76	76
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, 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
	<u>\$ 49</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 704</u>	<u>\$ 753</u>
Other Postretirement Benefit Plans assets:					
Money market funds	\$ 4	\$ —	\$ —	\$ —	\$ 4

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Equity securities:					
Domestic	—	3	—	—	3
International	9	—	—	—	9
Debt securities—Domestic	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	9	9
	<u>\$ 13</u>	<u>\$ 8</u>	<u>\$ —</u>	<u>\$ 14</u>	<u>\$ 35</u>

As of December 31, 2019:**Defined Benefit Pension Plan assets:**

Equity securities—Domestic	\$ 49	\$ —	\$ —	\$ —	\$ 49
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	632	632
Private equity funds	—	—	—	9	9
	<u>\$ 49</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 646</u>	<u>\$ 695</u>

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	—	—	—	8	8
	<u>\$ 13</u>	<u>\$ 8</u>	<u>\$ —</u>	<u>\$ 13</u>	<u>\$ 34</u>

1 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.

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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 represent 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, 2020 and 2019. 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	
	2020	2019	2020	2019	2020	2019
Benefit obligation:						
As of January 1	\$ 905	\$ 811	\$ 71	\$ 72	\$ 26	\$ 24
Service cost	17	16	2	2	—	—
Interest cost	31	34	2	3	1	1
Participants' contributions	—	—	—	2	—	—
Actuarial loss (gain)	104	88	4	8	3	3
Benefit payments	(44)	(42)	(4)	(6)	(2)	(2)
Administrative expenses	(3)	(2)	—	—	—	—
Plan amendment	—	—	1	(9)	—	—
Curtilment gain	—	—	—	(1)	—	—
As of December 31	<u>\$ 1,010</u>	<u>\$ 905</u>	<u>\$ 76</u>	<u>\$ 71</u>	<u>\$ 28</u>	<u>\$ 26</u>

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Fair value of plan assets:

As of January 1	\$ 695	\$ 546	\$ 34	\$ 30	\$ 17	\$ 16
Actual return on plan assets	105	131	2	5	1	1
Company contributions	—	62	3	3	3	2
Participants' contributions	—	—	—	2	—	—
Benefit payments	(44)	(42)	(4)	(6)	(2)	(2)
Administrative expenses	(3)	(2)	—	—	—	—
As of December 31	\$ 753	\$ 695	\$ 35	\$ 34	\$ 19	\$ 17
Unfunded position as of December 31	\$ (257)	\$ (210)	\$ (41)	\$ (37)	\$ (9)	\$ (9)
Accumulated benefit plan obligation as of December 31	\$ 907	\$ 813	N/A	N/A	\$ 24	\$ 26

Classification in Comparative Balance Sheet:

Noncurrent asset	\$ —	\$ —	\$ —	\$ —	\$ 19	\$ 17
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(257)	(210)	(41)	(37)	(26)	(24)
Net liability	\$ (257)	\$ (210)	\$ (41)	\$ (37)	\$ (9)	\$ (9)

Amounts included in comprehensive income:

Net actuarial loss (gain)	\$ 43	\$ (3)	\$ 4	\$ 5	\$ 3	\$ 3
Net prior service credit	1	—	—	(9)	—	—
Amortization of net actuarial loss	(17)	(10)	—	—	(1)	(1)
Amortization of prior service credit	—	—	1	—	—	—
	\$ 27	\$ (13)	\$ 5	\$ (4)	\$ 2	\$ 2

Amounts included in AOCL:*

Net actuarial loss (gain)	\$ 239	\$ 213	\$ 5	\$ 1	\$ 15	\$ 13
Prior service cost	1	—	(8)	(9)	—	—
	\$ 240	\$ 213	\$ (3)	\$ (8)	\$ 15	\$ 13

* 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 losses due to demographic experience, including assumption changes, were losses of \$104 million and \$88 million, and the changes between actual and expected return on plan assets were gains of

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\$61 million and \$94 million for the years ended December 31, 2020 and 2019, respectively.

- 2 For the other postretirement benefits, actuarial losses due to demographic experience, including assumption changes, were losses of \$5 million and \$2 million, and the changes between actual and expected return on plan assets were gains of \$1 million for each of the years ended December 31, 2020 and 2019, 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	
	2020	2019	2020	2019	2020	2019
	Service cost	\$ 17	\$ 16	\$ 2	\$ 2	\$ —
Interest cost on benefit obligation	31	34	2	3	1	1
Expected return on plan assets	(44)	(40)	(2)	(2)	—	—
Amortization of prior service credit	—	—	(1)	—	—	—
Amortization of net actuarial loss	17	10	—	—	1	1
Curtailment gain	—	—	—	(2)	—	—
Net periodic benefit cost	\$ 21	\$ 20	\$ 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	
	2020	2019	2020	2019	2020	2019
Assumptions used to determine benefit obligations:						
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 %	N/A
Assumptions used to determine net periodic benefit cost:						
Discount rate	3.43 %	4.25 %	3.19% - 3.47 %	3.11% - 4.26 %	3.43 %	3.43 %
Rate of compensation increase	3.65 %	3.65 %	4.58 %	4.58 %	4.10 %	N/A
Long-term rate of return on plan assets	7.00 %	7.00 %	5.02 %	5.88 %	N/A	N/A

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As of December 31, 2020, 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 2020 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					
	2021	2022	2023	2024	2025	2026 - 2030
Defined benefit pension plan	\$ 45	\$ 45	\$ 46	\$ 47	\$ 47	\$ 243
Other postretirement benefits	5	5	5	6	5	19
Non-qualified benefit plans	2	2	3	2	2	11
Total	\$ 52	\$ 52	\$ 54	\$ 55	\$ 54	\$ 273

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 2020 and \$25 million in 2019.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2020	2019
Current:		
Federal	\$ 6	\$ 9
State and local	17	12

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	23	21
Deferred:		
Federal	(22)	(2)
State and local	(1)	8
	(23)	6
Income tax expense	\$ —	\$ 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,	
	2020	2019
Federal statutory tax rate	21.0 %	21.0 %
Federal tax credits ⁽¹⁾	(20.5)	(13.4)
State and local taxes, net of federal tax benefit ⁽²⁾	10.1	6.5
Flow through depreciation and cost basis differences	(4.9)	1.5
Reversal of excess deferred income tax ⁽³⁾	(4.7)	(3.7)
Other	(1.0)	(0.7)
Effective tax rate	— %	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 Tax Cuts and Jobs Act (TCJA) 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.

Accumulated Deferred Income Tax Assets and Liabilities consist of the following (in millions):

	As of December 31,	
	2020	2019
Deferred Income Tax Assets:		
Employee benefits	\$ 137	\$ 120
Price risk management	42	36
Regulatory liabilities	23	22

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Tax credits	77	64
Depreciation and amortization	329	315
Other	9	6
Total Deferred Income Tax Assets	617	563
Deferred Income Tax Liabilities:		
Depreciation and amortization	834	812
Regulatory assets	130	105
Price risk management	12	10
Other	16	14
Total Deferred Income Tax Liabilities	992	941
Accumulated Deferred Income Tax Liability, net	\$ 375	\$ 378

As of December 31, 2020, PGE has federal credit carryforwards of \$77 million, consisting of PTCs, which will expire at various dates through 2040. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2020 and 2019 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2020, and 2019, PGE had no material unrecognized tax benefits.

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

In response to the TCJA, FERC issued a letter to Utilities requesting that the recipients either lower their rates to customers or show cause as to why they would elect not to do so. At PGE's request, FERC issued an order related to docket number EL18-109 on November 5, 2019 noting that PGE had shown cause as to why its transmission rate for its main transmission system should not be revised to reflect the reduced federal income tax rate due to the TCJA. However, PGE was required to update its transmission rate for its Colstrip transmission system, which PGE did on December 5, 2019. PGE's Power Operations (i.e., Marketing Function) is the sole customer of the Colstrip transmission system.

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, 2020, there were 241,281 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, 2020, there were 2,462,263 shares available for future issuance pursuant to the DRIP.

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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, 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

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,737,180 shares remain available for future issuance as of December 31, 2020.

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 \$1 million for the years ended December 31, 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 grants awarded in 2018 is based on two equally-weighted metrics: i) actual return on equity relative to allowed return on equity; and ii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted. The number of RSUs that may vest under grants awarded in 2019 and 2020 is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) power supply portfolio decarbonization—and relative 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 175% 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:

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	<u>2020</u>	<u>2019</u>
Risk-free interest rate	1.4 %	2.5 %
Expected term (in years)	2.9	3.0
Volatility	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 157.3%, 129.0%, and 69.0% of awarded performance-based RSUs for the respective 2020, 2019, and 2018 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was \$9 million for the year ended December 31, 2020 and \$7 million for 2019.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was \$11 million for the year ended December 31, 2020 and \$9 million for 2019. Such amounts differ from those reported in Other Paid-in Capital 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 \$2 million in both 2020 and 2019.

As of December 31, 2020, unrecognized stock-based compensation expense was \$13 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, 2020, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	<u>Payments Due</u>						<u>Total</u>
	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>Thereafter</u>	
Capital and other purchase commitments	\$ 237	\$ 33	\$ 20	\$ 1	\$ 1	\$ 55	\$ 347
Purchased power:							
Electricity purchases	250	257	284	278	249	2,886	4,204
Capacity contracts	9	9	9	9	9	—	45
Public utility districts	21	19	18	17	17	39	131
Natural gas	57	42	37	43	43	578	800
Coal and transportation	27	27	27	27	27	—	135

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Total	<u>\$ 601</u>	<u>\$ 387</u>	<u>\$ 395</u>	<u>\$ 375</u>	<u>\$ 346</u>	<u>\$ 3,558</u>	<u>\$ 5,662</u>
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Capital and other purchase commitments—Certain commitments have been made for 2021 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 2052, and power capacity contracts through 2028.

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

- 1 Grant County PUD for the Priest Rapids and Wanapum Hydroelectric Projects, and
- 2 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.

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

	Capacity Charges and Revenue Bonds as of December 31, 2020	PGE's Average Share as of December 31, 2020		Contract Expiration	Total PGE Contract Costs		
		Output	Capacity (in MW)		2020	2019	2018
Priest Rapids and Wanapum	\$ 1,880	8.6 %	163	2052	\$ 25	\$ 21	\$ 17
Wells	572	16.6	94	2028	23	16	11

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—PGE had coal and related rail transportation agreements with take-or-pay provisions related to the Boardman coal-fired generation plant (Boardman) that expired in December 2020 in conjunction with the cessation of coal fired generation at Boardman. The Company has a coal agreement with take-or-pay provisions related to Colstrip Units 3 and 4 coal-fired generation plant (Colstrip) that expires in December 2025.

Guarantees

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2020, 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.

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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, 2020 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):

	<u>2020</u>	<u>2019</u>
Operating lease cost	\$ 8	\$ 7
Finance lease cost:		
Amortization of right-of-use assets	\$ 5	\$ 3
Interest on lease liabilities	10	6
Total finance lease cost	\$ 15	\$ 9
Variable lease cost	\$ 12	\$ 19

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

Comparative Balance Sheet				
Classification		December 31, 2020	December 31, 2019	
Operating Leases:				
Operating lease right-of-use assets	Net Utility Plant	\$ 44	\$	51
Current liabilities	Obligations Under Capital Leases - Current	\$ 8	\$	8
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	36		43
Total operating lease liabilities*		\$ 44	\$	51
Finance Leases:				
Finance lease right-of-use assets	Net Utility Plant	\$ 145	\$	150
Current liabilities	Obligations Under Capital Leases - Current	\$ 16	\$	16
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	129		135
Total finance lease liabilities		\$ 145	\$	151

*Included in lease liabilities are \$25 million and \$32 million related to power purchase agreements for the years ended December 31, 2020 and 2019, respectively.

Lease term and discount rates were as follows:

	December 31, 2020	December 31, 2019
Weighted Average Remaining Lease Term (in years)		
Operating leases	26	24
Finance leases	28	29
Weighted Average Discount Rate		
Operating leases	3.6 %	3.5 %
Finance leases	7.3 %	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, 2020, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
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2021	\$	8	\$	16
2022		8		16
2023		8		14
2024		7		14
2025		1		13
Thereafter		45		222
Total lease payments		77		295
Less imputed interest		(33)		(150)
Total	\$	44	\$	145

Supplemental cash flow information related to leases was as follows (in millions):

	December 31, 2020	December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	\$ 8	\$ 7
Operating cash flows from finance leases	10	5
Financing cash flows from finance leases	6	4
Right-of-use assets obtained in leasing arrangements:		
Operating leases	\$ —	\$ 56
Finance leases	—	154

As of December 31, 2020, 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.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2020, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Colstrip	20.00 %	1986	\$ 566	\$ 387	\$ 7
Pelton/Round Butte	66.67 %	1958 / 1964	283	82	7
Total			\$ 849	\$ 469	\$ 14

* Excludes AROs and accumulated asset retirement removal costs.

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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 the initial steps toward decommissioning the facility. As of December 31, 2020, PGE's ARO liability for its 90% share of the decommissioning costs was \$44 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 was included among the Potentially Responsible Parties (PRPs) as it has historically owned or operated property near the river.

In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The Portland Harbor site remedial investigation had been completed pursuant to an agreement between the EPA and several PRPs

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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. 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 Superfund site 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 EPA announced on February 12, 2021 that 100% 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, 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. However, based on the above facts and remaining uncertainties, 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, although such costs 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 such costs to 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 environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, such as 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. Under the PHERA mechanism in 2020, PGE incurred and deferred \$6 million related to defense costs, net of an immaterial estimated refund as a result of PGE overearning in the regulated earnings test for this deferral. PGE's results of operations may be impacted to the extent such expenditures

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NOTES TO FINANCIAL STATEMENTS (Continued)			

are deemed imprudent by the OPUC or ineligible per the prescribed earnings test. The Company plans to seek recovery of any costs resulting from the 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.

Trojan Investment Recovery Class Actions

In 1993, PGE closed Trojan and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits sought damages totaling \$260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

In 2008, the OPUC issued an order (2008 Order) that required PGE to provide refunds, including interest, which were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in 2013 and by the OSC in 2014.

In 2015, based on a motion filed by PGE, the Marion County Circuit Court lifted the abatement on the class action proceedings and heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the state of Oregon.

In November 2019, the Court of Appeals issued an opinion that affirmed the Circuit Court dismissal. On December 30, 2019, the plaintiffs filed a motion for reconsideration, which the Court of Appeals denied on February 4, 2020.

On April 7, 2020, the Plaintiffs filed a petition with the OSC requesting review and reversal of the Court of Appeals opinion. On July 16, 2020, the OSC issued an order that denied the petition for review.

Deschutes River Alliance Clean Water Act Claims

In August 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company (Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon) that sought injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claimed PGE had violated certain conditions contained in PGE's Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleged the violations are related to PGE's operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam on the Deschutes River in central Oregon, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA has alleged that PGE's operation of the SWW has caused the above-referenced violations of the CWA, which in turn have degraded the fish and wildlife habitat of the Deschutes River below the Project and harmed the economic and personal interests of DRA's members and supporters.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

In March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and CTWS, which co-own the Project, filed separate motions to dismiss. CTWS initially appeared as a friend of the court, but subsequently was found to be a necessary party to the lawsuit and joined as a defendant.

In August 2018, the U.S. District Court of the District of Oregon (District Court) denied DRA's motions for partial summary judgment and granted PGE's and CTWS's cross-motions for summary judgment, ruling in favor of PGE and CTWS. The District Court found that DRA had not shown a genuine dispute of material fact sufficient to support its contention that PGE and CTWS were operating the Project in violation of the CWA, and accordingly dismissed the case.

In October 2018, DRA filed an appeal, and PGE and CTWS filed cross-appeals, to the Ninth Circuit Court of Appeals. The appeals are fully briefed and oral argument is set for May 7, 2021..

The Company cannot predict the outcome of this matter or determine the likelihood of whether the outcome will result in a material loss.

Shareholder Lawsuits

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* 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 complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees.

The Company intends to vigorously defend against the lawsuit. Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

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, against one current and one former PGE executive and several members of the Company's Board of Directors (collectively, the "Individual Defendants") 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 Individual 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.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

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, against one current and one former PGE executive and all 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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698, against one current and one former PGE executive and several 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.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

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.

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)
1	Balance of Account 219 at Beginning of Preceding Year				(6,431,626)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(3,183,476)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(3,183,476)
5	Balance of Account 219 at End of Preceding Quarter/Year				(9,615,102)
6	Balance of Account 219 at Beginning of Current Year				(9,615,102)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(1,489,803)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(1,489,803)
10	Balance of Account 219 at End of Current Quarter/Year				(11,104,905)

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

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1	(808)		(6,432,434)		
2			(3,183,476)		
3					
4			(3,183,476)	213,848,540	210,665,064
5	(808)		(9,615,910)		
6	(808)		(9,615,910)		
7			(1,489,803)		
8					
9			(1,489,803)	154,620,730	153,130,927
10	(808)		(11,105,713)		

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FOOTNOTE DATA			

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Comprised of the net amount of the actuarial valuation of \$(2,396,295) of non-qualified benefit plans net of taxes of \$658,981 and reclassification of stranded tax effects due to Tax Reform of \$(1,446,162).

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Comprised of the net amount of the actuarial valuation of \$(2,054,894) of non-qualified benefit plans net of taxes of \$565,091.

**SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION**

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	9,353,889,754	9,353,889,754
4	Property Under Capital Leases	188,767,638	188,767,638
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,463,893,390	1,463,893,390
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	11,006,550,782	11,006,550,782
9	Leased to Others		
10	Held for Future Use	8,359,324	8,359,324
11	Construction Work in Progress	430,009,860	430,009,860
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	11,444,919,966	11,444,919,966
14	Accum Prov for Depr, Amort, & Depl	4,871,352,378	4,871,352,378
15	Net Utility Plant (13 less 14)	6,573,567,588	6,573,567,588
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,483,327,657	4,483,327,657
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	388,024,721	388,024,721
22	Total In Service (18 thru 21)	4,871,352,378	4,871,352,378
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,871,352,378	4,871,352,378

Name of Respondent

Portland General Electric Company

This Report Is:

(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)

Submission Date: 04/16/2021

Year/Period of Report

End of 2020/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
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					25
					26
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					29
					30
					31
					32
					33

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year
			Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
			3
			4
			5
			6
			7
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			12
			13
			14
			15
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			17
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			21
			22

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	195,264,816	7,956,109
4	(303) Miscellaneous Intangible Plant	563,164,236	29,473,714
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	758,429,052	37,429,823
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,161,625	90
9	(311) Structures and Improvements	258,900,489	-6,679
10	(312) Boiler Plant Equipment	614,310,310	14,472,002
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	188,750,229	78,190
13	(315) Accessory Electric Equipment	55,267,293	448,812
14	(316) Misc. Power Plant Equipment	15,016,041	-114,420
15	(317) Asset Retirement Costs for Steam Production	75,980,571	1,039,281
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,212,386,558	15,917,276
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	6,053,903	
28	(331) Structures and Improvements	84,069,521	7,871,611
29	(332) Reservoirs, Dams, and Waterways	358,769,141	1,334,916
30	(333) Water Wheels, Turbines, and Generators	76,994,707	3,288,184
31	(334) Accessory Electric Equipment	31,601,534	3,036,840
32	(335) Misc. Power PLant Equipment	21,315,447	514,060
33	(336) Roads, Railroads, and Bridges	15,391,900	624,094
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	594,201,281	16,669,705
36	D. Other Production Plant		
37	(340) Land and Land Rights	26,960,038	
38	(341) Structures and Improvements	230,103,104	2,333,557
39	(342) Fuel Holders, Products, and Accessories	295,883,557	92,640
40	(343) Prime Movers		
41	(344) Generators	2,406,329,698	157,837,227
42	(345) Accessory Electric Equipment	121,136,967	659,921
43	(346) Misc. Power Plant Equipment	44,080,984	2,340,137
44	(347) Asset Retirement Costs for Other Production	22,576,353	2,766,486
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,147,070,701	166,029,968
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,953,658,540	198,616,949

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	17,269,685	31,759
49	(352) Structures and Improvements	30,274,032	502,940
50	(353) Station Equipment	499,772,267	75,850,794
51	(354) Towers and Fixtures	48,824,328	7,016,123
52	(355) Poles and Fixtures	83,364,423	17,796,023
53	(356) Overhead Conductors and Devices	169,438,106	31,239,961
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	286,332	
57	(359.1) Asset Retirement Costs for Transmission Plant	34,109	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	849,263,282	132,437,600
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	19,099,994	40,776
61	(361) Structures and Improvements	46,326,090	696,987
62	(362) Station Equipment	559,680,235	63,208,353
63	(363) Storage Battery Equipment	393,191	5,924
64	(364) Poles, Towers, and Fixtures	420,260,020	51,280,987
65	(365) Overhead Conductors and Devices	664,059,809	43,017,178
66	(366) Underground Conduit	29,515,629	1,454,076
67	(367) Underground Conductors and Devices	907,226,219	26,048,248
68	(368) Line Transformers	469,865,714	20,208,641
69	(369) Services	495,383,566	26,139,632
70	(370) Meters	185,286,768	17,387,057
71	(371) Installations on Customer Premises	1,749,713	630,425
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	117,253,253	18,298,538
74	(374) Asset Retirement Costs for Distribution Plant	476,732	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,916,576,933	268,416,822
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	9,622,353	-49,999
87	(390) Structures and Improvements	151,444,048	5,665,551
88	(391) Office Furniture and Equipment	160,507,769	14,937,201
89	(392) Transportation Equipment	78,457,262	8,376,552
90	(393) Stores Equipment	3,877,884	490,280
91	(394) Tools, Shop and Garage Equipment	23,093,384	1,601,629
92	(395) Laboratory Equipment	8,901,072	5,846,080
93	(396) Power Operated Equipment	44,630,769	3,614,453
94	(397) Communication Equipment	179,228,998	21,995,221
95	(398) Miscellaneous Equipment	1,295,282	-417
96	SUBTOTAL (Enter Total of lines 86 thru 95)	661,058,821	62,476,551
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	65,289	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	661,124,110	62,476,551
100	TOTAL (Accounts 101 and 106)	11,139,051,917	699,377,745
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,139,051,917	699,377,745

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				1
				2
1,610,806	438,909		202,049,028	3
41,267,619			551,370,331	4
42,878,425	438,909		753,419,359	5
				6
				7
		-832,853	3,328,862	8
108,779,931	-95,531	-32,720,154	117,298,194	9
347,558,126	-452,059	-9,965,453	270,806,674	10
				11
115,959,180	-259		72,868,980	12
31,570,281	-33,854	-159,711	23,952,259	13
8,240,304	-45,881	-12,716	6,602,720	14
33,910,136	-8,198,453		34,911,263	15
646,017,958	-8,826,037	-43,690,887	529,768,952	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
			6,053,903	27
11,427	-1,445,242		90,484,463	28
	-1,638,644		358,465,413	29
	-1,468,200		78,814,691	30
	-352,319		34,286,055	31
	-3,426,212		18,403,295	32
	-318,123		15,697,871	33
			5,128	34
11,427	-8,648,740		602,210,819	35
				36
	-2,855,604		24,104,434	37
37,597	-972,203	42,740,467	274,167,328	38
49,774	-7,418,947		288,507,476	39
				40
3,989,761	-5,047,172		2,555,129,992	41
218,494	-695,947		120,882,447	42
131,152	-678,130		45,611,839	43
			25,342,839	44
4,426,778	-17,668,003	42,740,467	3,333,746,355	45
650,456,163	-35,142,780	-950,420	4,465,726,126	46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
	-9,638		17,291,806	48
	-362,293		30,414,679	49
8,207,803	-2,007,165		565,408,093	50
1,924,617			53,915,834	51
68,469	-71,735		101,020,242	52
1,614,470	-153,341		198,910,256	53
				54
				55
			286,332	56
			34,109	57
11,815,359	-2,604,172		967,281,351	58
				59
	-11,664		19,129,106	60
499,530	-251,112		46,272,435	61
4,300,447	-1,752,759		616,835,382	62
			399,115	63
3,779,706	-8,733,490		459,027,811	64
509,953	-3,723,776		702,843,258	65
	-33,689		30,936,016	66
154,306	-6,321,237		926,798,924	67
394,231	-1,712,575		487,967,549	68
64,064	-1,453,907		520,005,227	69
6,727,172	-482,584		195,464,069	70
			2,380,138	71
				72
2,846,065	-4,493,789		128,211,937	73
			476,732	74
19,275,474	-28,970,582		4,136,747,699	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			9,572,354	86
575,749	-1,075,200	237,416	155,696,066	87
22,640,354	159,191		152,963,807	88
6,062,996	-420,797	481,788	80,831,809	89
87,819			4,280,345	90
1,024,022	-25,441		23,645,550	91
743,541			14,003,611	92
6,818,876		-481,788	40,944,558	93
849,485	-290,037		200,084,697	94
6,704			1,288,161	95
38,809,546	-1,652,284	237,416	683,310,958	96
				97
			65,289	98
38,809,546	-1,652,284	237,416	683,376,247	99
763,234,967	-67,930,909	-713,004	11,006,550,782	100
				101
				102
				103
763,234,967	-67,930,909	-713,004	11,006,550,782	104

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 32 Column: e

Includes activities of capitalized lease assets.

Schedule Page: 204 Line No.: 37 Column: e

Includes activities of capitalized lease assets.

Schedule Page: 204 Line No.: 39 Column: e

Includes activities of capitalized lease assets.

Schedule Page: 204 Line No.: 41 Column: e

Includes activities of capitalized lease assets.

Schedule Page: 204 Line No.: 87 Column: e

Includes activities of capitalized lease assets.

Schedule Page: 204 Line No.: 104 Column: d

Includes \$631.5M retirement of the Boardman coal plant in 4Q 2020.

Schedule Page: 204 Line No.: 104 Column: e

Includes \$(41.5)M adjustments to correctly classify cost of removal charges improperly classified as Utility Plant in prior periods.

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Damascus, Clackamas County, OR	2007	Future	543,591
3	Sewell, Washington County, OR	2008	Future	2,869,529
4	Sewell Easement, Washington County, OR	2009	Future	331,186
5	Evergreen, Washington County, OR	2019	Future	3,600,000
6	Boardman, Morrow County, OR	2020	Future	832,853
7	Other Land and Land Rights	Various	Various	182,165
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			8,359,324

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	Build Integrated Operations Center	109,122,893
2	Repower Faraday Units 1-5	74,212,574
3	Substation Communication Upgrade	27,560,149
4	Build Butler Substation	18,104,180
5	Roseway Substation Expansion	18,003,672
6	Advanced Distribution Management System Upgrade	17,488,039
7	Upgrade Physical Access Control System	12,674,920
8	Build Evergreen Substation	12,589,326
9	Willbridge Substation Conversion	9,041,729
10	Brookwood Substation Conversion	8,539,069
11	Build Helvetia Substation	7,918,308
12	Colstrip Coal Capital Project	7,858,593
13	Marquam Substation Feeder Addition	7,254,609
14	Hydro Control System Upgrade	7,251,677
15	Harborton Reliability Project	7,460,287
16	Distribution System Construction	4,357,198
17	Horizon Substation Transformer Installation	3,655,445
18	St. Mary's West Substation System Protection Upgrade	3,595,653
19	Build Sherwood Training Center	3,304,414
20	Energy Storage System	3,209,071
21	Blue Lake Substation Upgrade	3,117,272
22	South Milliken Distribution Line Rebuild	3,011,243
23	River District Infrastructure - Install Vaults and Conduits	2,947,132
24	Arleta-Holgate Conversion	2,640,166
25	Centennial Substation Upgrades	2,609,511
26	Pelton Round Butte Mitigation Enhancement Fund	2,532,257
27	Stephens Substation Conversion	2,398,768
28	Orengo Substation Rebuild	2,208,085
29	Small Generator/Qualified Facility (QF) Interconnection	1,938,850
30	Distribution Line Construction	1,882,874
31	Carty/Boardman Separation Project	1,882,802
32	Restore Beaver GT Unit 5	1,815,035
33	Upgrade IVR System	1,604,348
34	Distributed Control Software Upgrade	1,577,547
35	Replace Exhaust Frame and Diffuser	1,558,942
36	Install Load Bank	1,358,029
37	Replace or Rewind Failed Transformers	1,268,202
38	Upgrade Excitation System	1,114,170
39	Canyon Substation Upgrade	1,020,442
40		
41	Minor Projects, <\$1 million, represents 7% of the Total CWIP Balance	28,322,379
42		
43	TOTAL	430,009,860

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 216 Line No.: 12 Column: b

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.

Schedule Page: 216 Line No.: 26 Column: b

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.

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	4,914,258,659	4,914,258,659		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	315,333,112	315,333,112		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-3,966,273	-3,966,273		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,325,668	6,325,668		
7	Other Clearing Accounts	67,151	67,151		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	317,759,658	317,759,658		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	686,212,927	686,212,927		
13	Cost of Removal	10,841,489	10,841,489		
14	Salvage (Credit)	2,161,538	2,161,538		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	694,892,878	694,892,878		
16	Other Debit or Cr. Items (Describe, details in footnote):	-22,404,703	-22,404,703		
17					
18	Book Cost or Asset Retirement Costs Retired	-31,393,079	-31,393,079		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,483,327,657	4,483,327,657		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	380,845,848	380,845,848		
21	Nuclear Production				
22	Hydraulic Production-Conventional	274,374,882	274,374,882		
23	Hydraulic Production-Pumped Storage				
24	Other Production	987,247,487	987,247,487		
25	Transmission	372,753,724	372,753,724		
26	Distribution	2,181,668,233	2,181,668,233		
27	Regional Transmission and Market Operation				
28	General	286,437,483	286,437,483		
29	TOTAL (Enter Total of lines 20 thru 28)	4,483,327,657	4,483,327,657		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 12 Column: c

\$631.5M due to retirement of Boardman Coal Plant in Q4 2020.

Schedule Page: 219 Line No.: 16 Column: c

Other Debit or Credit items as follows:

-\$ (41.5)M Reduction to accumulated reserve with a corresponding offset to Utility Plant to correctly classify cost of removal charges improperly classified as Utility Plant in prior periods.

-\$15.9M Due to reclassification of expected Boardman Salvage proceeds not yet realized from accumulated reserve to other regulatory liabilities (254.3).

-\$2.4M Due to losses on retirements of utility plant.

-\$0.7M Due to other reserve transfers and adjustments.

Schedule Page: 219 Line No.: 18 Column: c

Retirement of Boardman Asset Retirement Cost balance.

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
 - (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
 - (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	121 SW Salmon Street Corporation			
2	Common Stock	04/01/75		1,000
3	Equity in Earnings			79,877,869
4	Sub - TOTAL			79,878,869
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			14,994
9	Sub - TOTAL			24,994
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
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29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	77,539,661	TOTAL	79,903,863

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

- 4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
- 5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
- 6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- 7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
- 8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

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)	Line No.
				1
		1,000		2
2,791,607		82,669,476		3
2,791,607		82,670,476		4
				5
				6
		10,000		7
-593,516	-14,994	-593,516		8
-593,516	-14,994	-583,516		9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
2,198,091	-14,994	82,086,960		42

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	34,191,533	17,886,804	Generation
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	18,665,272	21,101,356	Transmission & Dis
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,724,986	14,628,422	Generation
8	Transmission Plant (Estimated)	225,427	570,226	Transmission
9	Distribution Plant (Estimated)	7,083,996	8,054,839	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,252,410	1,875,277	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	51,952,091	46,230,120	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,657,581	2,688,473	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	89,801,205	66,805,397	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 1 Column: c

Reduction primarily due to closure of Boardman plant at the end of October 2020.

Schedule Page: 227 Line No.: 7 Column: c

Reduction primarily due to the closure of the Boardman plant at the end of October 2020 with its remaining inventory written off to account 254.

Schedule Page: 227 Line No.: 11 Column: b

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

Schedule Page: 227 Line No.: 11 Column: c

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

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2021	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	70,120.00		10,028.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	785.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	69,335.00		10,028.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,201.44		193.15	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	193.15			
40	Balance-End of Year	1,008.29		193.15	
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) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transfersors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
10,032.00		10,030.00		95,300.00		195,510.00		1
								2
								3
				1,321.00		1,321.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						785.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
10,032.00		10,030.00		96,621.00		196,046.00		28
								29
								30
								31
								32
								33
								34
								35
193.15		193.15		3,042.95		4,823.84		36
								37
								38
				193.15		386.30		39
193.15		193.15		2,849.80		4,437.54		40
								41
								42
								43
								44
					2			5
								45
								46

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2021	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

- 6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
- 7. Report on Lines 8-14 the names of vendors/transferrors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
- 8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
- 9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
- 10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
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								46

Name of Respondent

Portland General Electric Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

Date: 04/16/2021

Year/Period of Report

End of 2020/Q4

Document Accession #: 20210420-8026

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

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 Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	421,121,474	3,397,140		1,900,000	95,486,982
24	PGE has the authority to continue					
25	the recovery of the expense in					
26	rates until decommissioning is					
27	complete, as authorized by OPUC					
28	(Order No. 07-015, dtd 1/12/2007)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	421,121,474	3,397,140		1,900,000	95,486,982

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 23 Column: e

\$1,900,000 - Recovery of Trojan decommissioning costs included in retail prices, until decommissioning is complete, as authorized by OPUC (Order #07-015, dtd 1/12/2007 and updated by Order #18-464), offset in Account 407.

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	17-068	1,019	561.7		456
23	18-071	15,120	561.7		456
24	19-076	12,816	561.7	5,379	456
25	19-080	34,635	561.7	34,635	456
26	19-081	22,891	561.7	22,891	456
27	20-082	8,995	561.7	8,995	456
28	20-083	26,444	561.7	26,444	456
29	20-084	31,238	561.7	30,036	456
30	20-085	281	561.7	137	456
31	ASIS-001	24,292	561.7	24,292	456
32	LPQ0001	14,537	561.7	14,551	456
33	SRPL-001	3,162	561.7	3,162	456
34					
35					
36					
37					
38					
39					
40					

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Tax Benefits Related to Book/Tax Basis Differences	32,287,318	8,622,486			40,909,804
2	Previously Flowed to Customers	12,246,913	3,270,598			15,517,511
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Price Risk Management	95,030,232	516,500,277	VARIOUS	487,350,329	124,180,180
7						
8	Deferred Broker Settlement		29,950,614	VARIOUS	28,978,575	972,039
9						
10	Intervenor Funding (original deferral per OPUC	954,680	568,717	VARIOUS	940,282	583,115
11	Order No. 03-388 dtd 7/2/2003)					
12						
13	Coyote Springs Major Maintenance Accrual LTSA	2,546,405	2,307,002	VARIOUS	1,978,908	2,874,499
14	(per OPUC GRC 95-1216, dtd 11/20/1995)					
15						
16	Residual Deferred Account	312,049	6,567	182.3	313,418	5,198
17	(per OPUC Order No. 10-279 dtd 7/23/2010)					
18						
19	Glass Insulator Deferral	5,505,228		571	106,333	5,398,895
20	(per OPUC Order No. 10-478 dtd 12/17/2010;					
21	UE 215 First Revenue Requirement Stipulation)					
22	Amortization period: 56 years					
23						
24	Pension Funding	212,838,977	43,644,096	219	16,864,727	239,618,346
25	Postretirement Funding	31,897		219	31,897	
26	(Per SFAS No. 158 adopted 12/31/2006;					
27	OPUC Order No. 07-051 dtd 2/12/2007)					
28						
29	Boardman Decommissioning Balancing	(46,738)	163,829	VARIOUS	168,222	-51,131
30	(Per Advice No. 11-07 dtd 05/27/2011)					
31						
32	Automated Demand Response Cost Recovery Mechanism	(150,658)	8,826,802	VARIOUS	8,417,450	258,694
33	(Per OPUC Advice No. 17-29, dtd 11/13/17)					
34	(Amortization period 1/1/2020-12/31/2020)					
35						
36	Demand Response Testbed	284,945	11,073,611	VARIOUS	11,358,556	
37	(Per OPUC Order No. 19-425, dtd 12/06/2019)					
38	(Amortization period 1/1/2020-12/31/2020)					
39						
40	CET Deferral (2014-2018 vintages)	9,123,877	1,049,031	421/903	3,831,482	6,341,426
41	(amortization per OPUC Order No. 17-511,					
42	dtd 12/18/17)					
43	(Amortization period 01/01/2018-12/31/2022)					
44	TOTAL	422,858,216	789,658,895		685,973,036	526,544,075

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1						
2	Schedule 110 Energy Efficiency (per OPUC Advice No. 10-01)	4,550	1,084,590	VARIOUS	1,078,680	10,460
3						
4						
5	Deferred Cost - Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708)	2,296,459	2,579,652	VARIOUS	4,616,365	259,746
6						
7	(Amortization period 1/1/2020-12/31/2021)					
8						
9	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708)	4,426,480	4,573,751	VARIOUS	8,069,003	931,228
10						
11	(Amortization period 1/1/2020-12/31/2021)					
12						
13	Gresham Privilege Tax Collection Deferral (Advice No. 17-05, Schedule 134, dtd 02/24/17)	4,799,365	607,519	407.3	1,961,465	3,445,419
14						
15	(Amortization period 1/1/2018-12/31/2022)					
16						
17	Portland Harbor Environmental Remediation Deferral (Per OPUC Order No. 17-071, Docket No. UM1789, dtd 03/02/17)	14,631,343	21,170,363	VARIOUS	13,484,767	22,316,939
18						
19						
20						
21						
22	Residential Sch123 SNA Deferral-2017 (reauthorized Advice No. 16-23, dtd 11/23/2016)	(77,129)	1,094,146	254/456	1,017,017	
23						
24						
25	Residential Sch123 SNA Deferral-2018 (reauthorized Advice No. 16-23, dtd 11/23/2016)	4,484,188	764,062	456	5,064,427	183,823
26						
27	amortization period 1/1/2020-12/31/2020)					
28						
29	Lost Revenue Recovery-2017 (Per OPUC Order No. 16-359 dtd 9/26/2016, amortization period 1/1/2019-12/31/2019, per Advice No. 17-24)	15,392	37,703	456	53,095	
30						
31						
32						
33						
34	Non-residential Sch 123 SNA Deferral-2020 (Reauthorized Advice No. 16-23, dtd 11/23/2016)		15,799,242	VARIOUS	15,759,214	40,028
35						
36						
37	Residential Sch123 SNA Deferral-2020 (Reauthorized Advice No. 16-23, dtd 11/23/2016)		9,518,927	421/456	20,993	9,497,934
38						
39						
40	Lost Revenue Recovery-2019 (Per OPUC Order No. 16-359 dtd 9/26/2016)		325,100			325,100
41						
42						
43	Interest Rate Swap	4,583,799	26,044	428	182,308	4,427,535
44	TOTAL	422,858,216	789,658,895		685,973,036	526,544,075

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Interest Rate Hedges for Long Term Debt					
2	Amortization period: 30 years					
3						
4	Transportation Electrification Prgm	309,603	267,260	107	6,011	570,852
5	(Per UM 1811, Order No. 18-124, dtd 4/12/2018)					
6						
7	Multifamily Water Heater	1,290,543	7,172,987	VARIOUS	7,679,741	783,789
8	(Per Advice Filing No. 17-06, UM-1827,					
9	Order No. 17-224, dtd 6/27/2017)					
10	(Amortization period 1/1/2020-12/31/2020)					
11						
12	Multnomah County Business Income Tax Balancing	217,795		242	217,795	
13	(per Advice 11-27 dtd 10/27/2012)					
14						
15	Community Solar	341,418	1,968,505	VARIOUS	1,176,897	1,133,026
16	(Per UM-1977, OPUC Order No. 18-477,					
17	dtd 12/19/2018)					
18						
19	Photovoltaic Volumetric Incentive Pilot		20,748,371	VARIOUS	20,748,371	
20	(Per OPUC Order No. 10-198 dtd 5/28/2010)					
21	(Reauthorized OPUC Order No. 15-185 dtd 6/09/2015)					
22						
23	Residential Sch123 SNA Deferral-2019	10,785,726	15,970,513	182.3/456	13,393,334	13,362,905
24	(Reauthorized Advice No. 16-23, dtd 11/23/2016)					
25						
26	Non-residential Sch 123 SNA Deferral 2019	3,783,559	4,748,685	182.3/456	4,274,571	4,257,673
27	(reauthorized Advice No. 16-23, dtd 11/23/2016)					
28						
29	Residential Battery Energy Storage Pilot		17,745	920	6,140	11,605
30	(Per UM-2078, Order No. 20-208, dtd 7/6/2020)					
31						
32	Wheatridge Renewable Energy Farm		1,588,025	553	4,411	1,583,614
33	(Per UE-370, Order No. 20-279, dtd 8/26/2020)					
34						
35	Emergency Wildfire		25,191,476	421/593	9,731,255	15,460,221
36	(Per UM-2115, Order No. 20-389, dtd 10/27/2020)					
37						
38	COVID-19		18,438,403	VARIOUS	8,199,784	10,238,619
39	(Per UM-2064, Order No. 20-376, dtd 10/27/2020)					
40						
41	Oregon Commercial Activity Tax		8,868,445	VARIOUS	8,887,213	-18,768
42	(Per UM-2037, UE 368, Order No. 20-029,					
43	dtd 01/29/2020)					
44	TOTAL	422,858,216	789,658,895		685,973,036	526,544,075

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1						
2	OPUC Fee Deferral		1,113,751			1,113,751
3	(Per UM-2046, Order No. 20-411, dtd 11/05/2020)					
4						
5						
6						
7						
8						
9						
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42						
43						
44	TOTAL	422,858,216	789,658,895		685,973,036	526,544,075

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 6 Column: d

PRM 182.3/254/547/555

Schedule Page: 232 Line No.: 8 Column: d

Deferred Broker Settlements 134/182.3/254/547/555

Schedule Page: 232 Line No.: 10 Column: d

Intervenors: 182.3/407.3

Schedule Page: 232 Line No.: 13 Column: d

Coyote Springs MMA: 182.3/407.3

Schedule Page: 232 Line No.: 29 Column: d

Boardman Decomm: 421/431/456

Schedule Page: 232 Line No.: 32 Column: b

Beginning balance includes a reclassification of \$284,945 to Demand Response Testbed.

Schedule Page: 232 Line No.: 32 Column: d

ADR: 143/182.3/232/407.3/421

Schedule Page: 232 Line No.: 36 Column: b

Beginning balance includes a reclassification of \$284,945 from Automated Demand Response Cost Recovery Mechanism.

Schedule Page: 232 Line No.: 36 Column: d

Demand Response Testbed: 182.3/251/407.3/421/431

Schedule Page: 232.1 Line No.: 2 Column: d

SCH 110 Energy Efficiency: 254/407.3/431

Schedule Page: 232.1 Line No.: 5 Column: b

Beginning balance includes a reclassification of \$77,083 from Res. Thermo Direct Install and \$2,297,553 from Res. Pricing Program.

Schedule Page: 232.1 Line No.: 5 Column: d

182.3/507.3/421.

Schedule Page: 232.1 Line No.: 9 Column: b

Beginning balance includes a reclassification of \$2,096,121 from Res. Thermo Direct Install.

Schedule Page: 232.1 Line No.: 9 Column: d

182.3/407.3.

Schedule Page: 232.1 Line No.: 17 Column: d

PHERA: 107/131/182.3/421/923

Schedule Page: 232.1 Line No.: 34 Column: d

NonRes SNA 2020: 182.3/254/407.4/421/431/456/904.

Schedule Page: 232.2 Line No.: 7 Column: b

Beginning balance includes a reclassification of \$270,000 from Res. Water Heater.

Schedule Page: 232.2 Line No.: 7 Column: d

182.3/242/407.3

Schedule Page: 232.2 Line No.: 15 Column: d

Community Solar: 407.3/417.1/421

Schedule Page: 232.2 Line No.: 19 Column: d

FiT: 131/254/407.3/421/431/555

Schedule Page: 232.2 Line No.: 23 Column: b

Beginning balance includes a reclassification of \$1,175,939 from Residential Sch 123 SNA Deferral-2019 to Non-residential Sch 123 SNA Deferral-2019.

Schedule Page: 232.2 Line No.: 26 Column: b

Beginning balance includes a reclassification of \$1,175,939 from Residential Sch 123 SNA Deferral-2019 to Non-residential Sch 123 SNA Deferral-2019.

Schedule Page: 232.2 Line No.: 38 Column: d

COVID-19: 182.3/421/431/904

Schedule Page: 232.2 Line No.: 41 Column: d

OCAT: 182.3/254/407.4/431/904

MISCELLANEOUS DEFERRED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2	Misc. Undistributed Charges	354,221	475,718	Various	537,675	292,264
3						
4	Net Co-owner / Trust Contributi	316,103	80,197,317	Various	80,192,838	320,582
5						
6	Deferred Revolving Credit	1,276,225		431	326,109	950,116
7	Agreement Fees					
8	amort. through November 2023					
9						
10	Dispatchable Generation	10,802,749	571,047	903	1,806,129	9,567,667
11	various amort. periods from					
12	2009 and extending through 2028					
13						
14	Utility Property Sales-	43,949	32,329			76,278
15	Selling Expenses					
16						
17						
18						
19						
20						
21						
22						
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24						
25						
26						
27						
28						
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45						
46						
47	Misc. Work in Progress	687,223				34,304
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	13,480,470				11,241,211

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Related	311,034,575	319,689,145
3	Regulatory Liabilities	22,112,547	21,459,037
4	Employee Benefits	119,856,422	136,517,004
5	Price Risk Management	36,064,583	41,506,877
6	Tax Credits & NOL's	64,215,361	77,041,984
7	Other	5,704,912	12,016,102
8	TOTAL Electric (Enter Total of lines 2 thru 7)	558,988,400	608,230,149
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)	4,340,861	9,409,220
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	563,329,261	617,639,369

Notes

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 7 Column: b

Line 7 - Other

	Ending Bal 12/31/2019	Ending Bal 12/31/2020
Bad Debt Expense	\$1,231,143	\$4,301,616
Deferred Revenue	2,062,276	1,362,280
Nuclear Decommissioning Trust	7,632,027	8,492,158
Renewable Energy Development	3,761,140	3,653,395
Miscellaneous	-8,981,674	-5,793,347
Total Line 7 - Other	\$5,704,912	\$12,016,102

Schedule Page: 234 Line No.: 17 Column: b

Line 17 - Other Non-Utility

	Ending Bal 12/31/2019	Ending Bal 12/31/2020
Property Related	\$4,265,935	\$9,409,495
Employee Benefits	74,926	-275
Total Line 17 - Other Non-Utility	\$4,340,861	\$9,409,220

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

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)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total Common Stock	160,000,000		
5				
6	Account 204:			
7	No par Value Cumulative Preferred	30,000,000		
8				
9	Total Preferred Stock	30,000,000		
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Document Accession #: 20210420-8026

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
 4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
 5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
89,537,331	1,234,951,127					2
						3
89,537,331	1,234,951,127					4
						5
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Document Accession #: 20210420-8026 Submission Date: 04/16/2021

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208	
2	Parent equity contributions from employee stock purchase and	4,804,482
3	compensation and associated income tax benefits	
4	SUBTOTAL ACCOUNT 208	4,804,482
5		
6	Account 209	
7	Reduction in par or stated vaue of Common Stock	1,556,498
8	SUBTOTAL ACCOUNT 209	1,556,498
9		
10	Account 210	
11	Capital Restructuring Costs	49,120
12	SUBTOTAL ACCOUNT 210	49,120
13		
14	Account 211	
15	Miscellaneous paid in capital	640,957
16	Amortization of capital stock expense	-646,425
17	Tax benefits related to stock compensation plans	3,574,988
18	Reacquired common stock	-68,327
19	Former parent assumption of PGE tax liabilities of Non-Qualified Pn	610,028
20	Oregon tax credit related to PGE's separation from parent	8,317,516
21	SUBTOTAL ACCOUNT 211	12,428,737
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40	TOTAL	18,838,837

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 253 Line No.: 19 Column: b

Represents the assumption of PGE's tax liability by the Company's former parent company on taxable income related to the transfer of non-qualified plan liabilities to PGE from Portland General Holdings, recorded in 2005.

Schedule Page: 253 Line No.: 20 Column: b

PGE generated approximately \$13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by the Company's former parent company prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to its former parent; however, the former parent was unable to utilize these credits on its tax returns. PGE then utilized a portion of the tax credits to offset quarterly income tax payments due to the State of Oregon during periods subsequent to the separation, with no effect on income. In 2008 and 2009, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of related federal tax effect.

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

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

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - Bonds:		
2	First Mortgage Bonds -		
3	9.31% Medium-Term Note Series Due 8/11/2021	20,000,000	176,577
4	6.875% Series VI Due 8/1/2033	50,000,000	519,257
5			437,500 D
6	6.26% Series Due 5/1/2031	100,000,000	723,856
7	6.31% Series Due 5/1/2036	175,000,000	1,270,565
8	5.80% Series Due 6/1/2039	170,000,000	1,460,968
9	5.81% Series Due 10/1/2037	130,000,000	1,109,574
10			517,518 D
11	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
12	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
13	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
14	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	311,154
15	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	652,029
16	4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014	100,000,000	645,383
17	4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014	100,000,000	625,030
18	3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014	80,000,000	501,502
19	3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014	75,000,000	325,296
20	3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014	70,000,000	305,128
21	2.51% Series Due 1/6/2021 - Order No. 14-399 11/12/2014	140,000,000	592,932
22	3.98% Series Due 11/21/2047 - Order No. 16-152 04/21/2016	150,000,000	-99,510
23	3.98% Series Due 8/3/2048 - Order No. 16-152 04/21/2016	75,000,000	-44,757
24	4.47% SERIES DUE 12-11-2048 Order No. 16-152 04/21/2016	75,000,000	336,938
25	4.30% Series Due 4/11/2049 Order No. 18-453 12/04/2018	200,000,000	860,461
26	3.34% Series Due 10/15/2049 Order No. 18-453 12/04/2018	110,000,000	477,767
27	3.34% Series Due 1/15/2050 Order No. 18-453 12/04/2018	160,000,000	694,934
28	3.15% Series Due 4/1/2030 Order No. 18-454 12/4/2018	200,000,000	862,049
29	1.84% Series Due 12/10/2027 Order No. 20-169 5/22/2020	160,000,000	645,816
30	2.32% Series Due 12/10/2032 Order No. 20-169 5/22/2020	70,000,000	278,000
31			
32			
33	TOTAL	3,156,600,000	18,177,501

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Pollution Control Bonds (Guaranteed by Company) -		
2	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
3	City of Forsyth, MT Series 2.125% Due 05/01/2033 Order 09-099 3/26/2009	97,800,000	528,702
4			-1,956,000 P
5	City of Forsyth, MT Series 2.375% Due 05/01/2033 Order 09-099 3/26/2009	21,000,000	97,594
6	SUBTOTAL ACCOUNT 221	3,156,600,000	18,177,501
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33	TOTAL	3,156,600,000	18,177,501

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,862,000	3
08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500	4
						5
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000	6
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,500	7
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,000	8
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,000	9
						10
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	11
6/27/2013	06/15/2044	6/27/2013	06/15/2044	150,000,000	6,705,000	12
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	3,352,500	13
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000	14
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000	15
8/15/2014	8/15/2045	8/15/2014	8/15/2045	100,000,000	4,390,000	16
10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000	17
11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000	18
1/15/2015	1/15/2030	1/15/2015	1/15/2030	75,000,000	2,662,500	19
5/15/2015	5/15/2035	5/15/2015	5/15/2035	70,000,000	2,450,000	20
1/6/2016	1/6/2021	1/6/2016	1/6/2021	140,000,000	3,514,000	21
11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000	22
8/3/2017	8/3/2048	8/3/2017	8/3/2048	75,000,000	2,985,000	23
12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	3,352,500	24
4/19/2019	4/11/2049	12/11/2019	12/11/2049	200,000,000	8,600,000	25
10/15/2019	10/15/2049	10/15/2019	10/15/2049	110,000,000	3,674,000	26
11/15/2019	1/15/2050	11/15/2019	1/15/2050	160,000,000	5,344,000	27
4/27/2020	4/1/2030	4/27/2020	4/1/2030	200,000,000	4,270,000	28
12/10/2020	12/10/2027	12/10/2020	12/10/2027	160,000,000	171,733	29
12/10/2020	12/10/2032	12/10/2020	12/10/2032	70,000,000	94,733	30
						31
						32
				3,058,800,000	123,508,651	33

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
05/28/1998	05/01/2033	05/28/1998	05/01/2033		950,833	2
03/11/2020	05/01/2033	03/11/2020	05/01/2033	97,800,000	1,809,980	3
						4
03/11/2020	05/01/2033	03/11/2020	05/01/2033	21,000,000	406,872	5
				3,058,800,000	123,508,651	6
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				3,058,800,000	123,508,651	33

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	154,620,730
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	114,687,622
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	12,267,046
11	Regulatory Credits	-2,696,044
12	Other (See Footnote)	77,914,616
13		
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-23,755,734
16	Regulatory Debits	-90,830,152
17	Other (See Footnote)	-7,123,664
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-96,184,396
21	State & Local Tax Deduction	-17,543,049
22	Other (See Footnote)	-596,079
23		
24		
25		
26		
27	Federal Tax Net Income	120,760,896
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	25,359,788
30	Federal Credit Tax	-19,067,709
31	RTA Federal Tax Adjustment	56,789
32	Other Items Affecting Tax	-650,302
33	Total Federal Income Tax - PGE	5,698,567
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Name of Respondent Portland General Electric Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 12 Column: a**Line 12 - Deductions Recorded on Books Not Deducted for Return**

Qualified NDT	3,127,749
Meals & Entertainment	230,313
Political Activity	1,219,135
Bad Debts	11,165,359
Fines and Penalties	132,974
Employee Benefits	64,630,606
Federal Tax Expense	(16,541,171)
Orion Contingent Royalty Payments	(915,180)
Tax Finance Lease	2,456,483
Unamortized loss on reacquired debt	1,290,092
State & Local Tax Expense	15,702,693
Deferred Revenue	(2,386,347)
Miscellaneous	(2,198,090)
Total Other	77,914,616

Schedule Page: 261 Line No.: 17 Column: a**Line 17 - Income Recorded on Books Not Included in Return**

Key Man Life Insurance	(4,267,563)
OCI	(2,054,875)
Miscellaneous	(801,226)
Total Other	(7,123,664)

Schedule Page: 261 Line No.: 22 Column: a**Line 22 - Deductions on Return Not Charged Against Book Income**

Dividend Received Deduction	(33,000)
Prepaid	(947,670)
Renewable Energy Initiatives	(45,696)
Property Tax	(4,065,992)
Accumulated ARO Sullivan	4,299,949
Miscellaneous	196,330
Total Other	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

(596,079)

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	FERC Resale/Coord	212,665		881,009	874,939	
3	Income Tax		3,635,818	5,698,759	3,650,000	
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	3,589,927		24,553,447	13,625,004	1
6	Unemployment	72,425		66,763	137,293	
7	Power License	282,135	-34,115	2,109,735	1,908,831	
8	Superfund Tax					
9	SUBTOTAL Federal	4,157,152	3,601,703	33,309,713	20,196,067	1
10	State of Montana:					
11	Income Tax		-311,187	214,130	100,000	
12	Electric Energy Producers	211,170		761,901	649,148	
13	Property Taxes	3,894,921		7,959,294	7,927,096	
14	SUBTOTAL Montana	4,106,091	-311,187	8,935,325	8,676,244	
15	State of Oregon:					
16	Corp Excise Tax and CAT	243,008	7,929,519	15,804,465	11,024,261	
17	Property Taxes		31,686,422	69,058,223	73,054,662	-1,614,737
18	City Taxes & Licenses	3,504,987		46,038,477	45,858,355	1
19	Public Utility Comm Fees		-78,530	7,439,408	7,517,938	
20	Department of Energy		962,906	2,076,210	2,226,607	-1
21	Department of Enviro Quality	489,705		855,696	678,027	
22	Unemployment	220,011		1,428,468	1,618,459	-1
23	Water Power Fee		630,768	632,183		
24	Transportation Tax	524,680		2,120,589	2,094,787	-1
25	Workers Comp Assessment	-156,714		403,597	246,884	1
26	County & City Income Tax		692,035	344,203	335,000	
27	SUBTOTAL Oregon	4,825,677	41,823,120	146,201,519	144,654,980	-1,614,738
28	State of Washington:					
29	Property Taxes	2,383,257		2,220,400	2,339,540	
30	Sales Tax					
31	SUBTOTAL WASHINGTON	2,383,257		2,220,400	2,339,540	
32	State of Utah					
33	Income Tax					
34	SUBTOTAL Utah					
35	State of California:					
36	Corporate Franchise Tax		-1,065,125	359,174	150,000	
37	SUBTOTAL California		-1,065,125	359,174	150,000	
38	Canada					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	15,472,177	44,048,511	191,026,131	176,016,831	-1,614,737

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
218,735					881,009	2
	1,587,059	7,733,048			-2,034,289	3
						4
14,518,371		12,511,510			12,041,937	5
1,895		34,025			32,738	6
262,130	-255,024				2,109,735	7
						8
15,001,131	1,332,035	20,278,583			13,031,130	9
						10
	-425,317	234,952			-20,821	11
323,923		444,751			317,150	12
3,927,119		5,954,439			2,004,855	13
4,251,042	-425,317	6,634,142			2,301,184	14
						15
243,008	3,149,315	16,582,141			-777,677	16
-2,358	37,295,240	65,155,885			3,902,338	17
3,685,110		46,038,477				18
					7,439,408	19
	1,113,304	2,076,210				20
667,374					855,696	21
30,019		725,440			703,028	22
	-1,415				632,183	23
550,481		1,076,930			1,043,659	24
		204,965			198,632	25
	682,832	398,290			-54,087	26
5,173,634	42,239,276	132,258,338			13,943,180	27
						28
2,264,117		2,220,400				29
						30
2,264,117		2,220,400				31
						32
						33
						34
						35
	-1,274,299	371,812			-12,638	36
	-1,274,299	371,812			-12,638	37
						38
						39
						40
26,689,924	41,871,695	161,763,275			29,262,856	41

Name of Respondent Portland General Electric Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 17 Column: f

Line 17 -Adjustments

Property Tax Bill to Others	(1,628,834)
Property Tax BTO - Write Off	14,097
Total	(1,614,737)

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
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17							
18							
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47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
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			41
			42
			43
			44
			45
			46
			47
			48

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Tenant security deposits				160,000	160,000
2						
3	Deferred Liability for Transferred	555,126	421	19,609		535,517
4	Non-Qualified Plan Benefits					
5						
6	Reserve for Environmental	4,000,000				4,000,000
7	Remediation Costs					
8						
9	Deferral of Precedent Transmission	1,455,442	565	2,045,339	589,897	
10	Service Agreement with DET, EDF					
11						
12	Clean Fuels Program	8,841,842	232,926	4,622,756	6,448,793	10,667,879
13	OPUC 17-250 and 17-512					
14						
15	Price Risk Management	-295,008	555	657,390	952,398	
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	14,557,402		7,345,094	8,151,088	15,363,396

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 12 Column: d

The debits are expenses associated with the program, including administrative costs and other payments related to the initiatives the program supports.

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent

Portland General Electric Company

Document Accession #: 20210420-8026

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

Date: 04/16/2021

Year/Period of Report

End of 2020/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
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							9
							10
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NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	800,256,070	74,836,300	64,552,910
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	800,256,070	74,836,300	64,552,910
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	800,256,070	74,836,300	64,552,910
10	Classification of TOTAL			
11	Federal Income Tax	642,494,895	50,765,591	45,581,121
12	State Income Tax	147,727,378	22,561,243	17,784,010
13	Local Income Tax	10,033,797	1,509,466	1,187,779

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		182.3	11,835,673	254	20,458,160	819,161,947	2
							3
							4
			11,835,673		20,458,160	819,161,947	5
							6
							7
							8
			11,835,673		20,458,160	819,161,947	9
							10
			8,709,883		14,924,635	653,894,117	11
			2,937,900		5,192,269	154,758,980	12
			187,890		341,256	10,508,850	13

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Property Related	12,246,848		
4	Price Risk Management	10,335,254	14,202,728	12,133,871
5	Regulatory Assets	103,582,503	62,823,042	37,872,328
6	Regulatory Liabilities			
7	Other	14,282,925	1,606,313	820,584
8				
9	TOTAL Electric (Total of lines 3 thru 8)	140,447,530	78,632,083	50,826,783
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	882,642		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	141,330,172	78,632,083	50,826,783
20	Classification of TOTAL			
21	Federal Income Tax	99,034,001	55,105,802	35,619,693
22	State Income Tax	39,651,999	22,055,452	14,256,365
23	Local Income Tax	2,644,172	1,470,829	950,725

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
 4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		254	4,346,390	182.3	7,617,012	15,517,470	3
						12,404,111	4
						128,533,217	5
							6
						15,068,654	7
							8
			4,346,390		7,617,012	171,523,452	9
							10
							11
							12
							13
							14
							15
							16
							17
1,040,134	128,886	254	33	182.3	9	1,793,866	18
1,040,134	128,886		4,346,423		7,617,021	173,317,318	19
							20
729,234	90,480		3,234,964		5,527,017	121,450,917	21
291,468	36,008		1,042,894		1,960,262	48,623,914	22
19,432	2,398		68,565		129,742	3,242,487	23

NOTES (Continued)

Name of Respondent Portland General Electric Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 5 Column: a

	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

Schedule Page: 276 Line No.: 7 Column: a

	Beginning Balance	Ending 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

Schedule Page: 276 Line No.: 18 Column: a

	Beginning Balance	Ending Balance
Other	419,312	1,075,812
Trust Owned Life Insurance	463,330	718,054
Other	882,642	1,793,866

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Excess Deferred Income Taxes	304,215,185	190	12,162,046	3,278,370	295,331,509
2						
3	Gain on Asset Sales	1,866,501			54,018	1,920,519
4	(Per OPUC Order No. 01-777 dtd 8/31/2001)					
5						
6	Boardman Severance	9,017,932	456	4,978,961	2,635,332	6,674,303
7	Advice No.14-18, dtd 11/3/2014					
8						
9	Asset Retirement Obligations:	53,681,112	VARIOUS	41,472,216	24,626,647	36,835,543
10	Balancing Account					
11						
12	Carty Major Maintenance Deferral	587,055	456	2,553,070	3,201,412	1,235,397
13	(Per OPUC Order 15-356 UE-294					
14	dtd 11/3/15)					
15						
16	Colstrip Major Maintenance Deferral	5,376,030	254/456	3,328,603	3,199,452	5,246,879
17	(Per OPUC UE-319, Order No. 17-511,					
18	dtd 12/18/17)					
19						
20	Port Westward 1 Major Maint Deferral	469,146	456	2,099,699	3,864,524	2,233,971
21	(Per OPUC UE 262, Order No. 13-459,					
22	dtd 12/9/2013)					
23						
24	Port Westward 2 Major Maintenance Deferral	1,985,112			968,678	2,953,790
25	(Per OPUC 2015 GRC Docket UE-283,					
26	OPUC Order No.14-422, dtd 12/4/2014)					
27						
28	Zero Interest Program Loan Repayments	3,363,113	407/431/447	1,534,256	277,908	2,106,765
29	(Per Advice No. 05-19 dtd 12/20/2005)					
30						
31	Schedule 110 Energy Efficiency - Balancing Account	50,389	182.3	50,389		
32	(Per Advice No. 07-25 dtd 5/20/2008)					
33						
34	Sunway 3 Investment Deferral	477,430	407	45,480		431,950
35	(Per UM 1480 dtd 4/01/2010;					
36	(Amortization over 20 years commencing 2010)					
37						
38	Trojan Decommissioning Deferral	3,293,245	407	148,448	3,743,629	6,888,426
39	(Per OPUC UE-319, Order No.17-511,					
40	dtd 12/18/2017)					
41	TOTAL	408,556,713		151,854,371	164,712,767	421,415,109

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
 2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
 3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	(Amortization period 1/1/2019-12/31/2019)					
2						
3	PRC Acquisition	3,601,039			79,501	3,680,540
4	(Per OPUC UE-283 Final GRC Order No.14-422,					
5	dtd 12/04/2014, Second Partial					
6	Stipulation dtd 9/2/2014)					
7						
8	Deferred Broker Settlement	105,850	182.3	4,827,070	4,721,220	
9						
10	Photovoltaic Volumetric Incentive Pilot	2,900,321	182.3	16,311,858	17,955,652	4,544,115
11	(Per OPUC Order 10-198 dtd 5/28/2010					
12	reauthorized OPUC Order 15-185					
13	dtd 6/09/2015)					
14						
15	Portland Harbor Environmental Deferral	(2,766)				-2,766
16	(Per OPUC Order No. 17-071, UM-1789					
17	dtd 03/02/17)					
18						
19	Price Risk Management	1,469,031	182.3	47,524,699	64,407,602	18,351,934
20						
21	Monet NVPC QF Deferral-2019	1,156,116	555	138,896	2,386,433	3,403,653
22	(Per UE-335 NVPC Stipulation,					
23	OPUC Order No. 18-405)					
24						
25	Research & Development Tax Credits	4,733,455	190/923	13,793	738,395	5,458,057
26	(Per UM-1991, OPUC Order No. 18-464					
27	dtd 12/14/2018)					
28						
29	Postretirement Plans	8,385,769	182.3/219	5,987,869	877,473	3,275,373
30	(Per SFAS No. 158 adopted 12/31/2006;					
31	OPUC Order No. 07-051 dtd 2/12/2007)					
32						
33	Lease Obligation Balancing Account	751,148			405,656	1,156,804
34						
35	Direct Access Deferral - 2019	1,074,500	431/447	904,310	26,187	196,377
36	(Per UM-1301, Order No. 19-045					
37	dated 12/30/2019)					
38						
39	Direct Access Deferral - 2020				400,316	400,316
40	(Per UM-1301, Order No. 21-034					
41	TOTAL	408,556,713		151,854,371	164,712,767	421,415,109

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	dated 1/28/2021)					
2						
3	Ocat		182.3	2,832,008	2,832,008	
4	(Per UM-2037, UE 368, Order No.					
5	20-029, dtd 01/29/2020)					
6						
7	Monet NVPC QF Deferral 2020		555	1,560,699	3,374,475	1,813,776
8	(Per UM-1988, Order No. 19-441					
9	dtd 12/20/2019)					
10						
11	Residual Account		182.3	185,000	102,182	-82,818
12						
13	Demand Response Testbed		182.3	2,650,045	4,935,499	2,285,454
14	(Per OPUC Order No. 19-425, dtd 12/06/2019)					
15	(Amortization period 1/1/2020-12/31/2020)					
16						
17	Residential Sch123 SNA Deferral-2020		431	9,165	15,084,407	15,075,242
18	(Reauthorized Advice No. 16-23,					
19	dtd 11/23/2016)					
20						
21	Automated Demand Response Cost		182.3	535,791	535,791	
22	(Per OPUC Advice No. 17-29, dtd 11/13/17)					
23	(Amortization period 1/1/2020-12/31/2020)					
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	408,556,713		151,854,371	164,712,767	421,415,109

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 9 Column: c

101/108/165/228.2/254/407.3/456/924/925

Schedule Page: 278 Line No.: 16 Column: b

Beginning balance includes \$469,146 reclassification to PW1 MMA.

Schedule Page: 278 Line No.: 20 Column: b

Beginning balance is made up of a reclassification from Colstrip MMA.

ELECTRIC OPERATING REVENUES (Account 400)

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	969,909,454	917,792,335
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	619,175,770	638,317,031
5	Large (or Ind.) (See Instr. 4)	246,051,284	221,934,941
6	(444) Public Street and Highway Lighting	10,945,945	11,259,467
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,846,082,453	1,789,303,774
11	(447) Sales for Resale	184,596,850	203,335,776
12	TOTAL Sales of Electricity	2,030,679,303	1,992,639,550
13	(Less) (449.1) Provision for Rate Refunds	-5,767,072	-24,671,723
14	TOTAL Revenues Net of Prov. for Refunds	2,036,446,375	2,017,311,273
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,510,490	7,533,569
17	(451) Miscellaneous Service Revenues	917,276	1,918,764
18	(453) Sales of Water and Water Power	-20,340	-25,668
19	(454) Rent from Electric Property	13,829,360	11,854,326
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	94,787,137	98,951,224
22	(456.1) Revenues from Transmission of Electricity of Others	9,742,070	10,438,921
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	120,765,993	130,671,136
27	TOTAL Electric Operating Revenues	2,157,212,368	2,147,982,409

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.

8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.

9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,756,251	7,471,069	791,119	779,673	2
				3
6,173,372	6,603,269	110,654	109,890	4
3,445,801	3,180,993	267	262	5
48,379	49,360	197	194	6
				7
				8
				9
17,423,803	17,304,691	902,237	890,019	10
6,442,580	5,267,311	40	35	11
23,866,383	22,572,002	902,277	890,054	12
				13
23,866,383	22,572,002	902,277	890,054	14

Line 12, column (b) includes \$ 10,618,000 of unbilled revenues.

Line 12, column (d) includes 83,623 MWH relating to unbilled revenues

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company		//	2020/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

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

Schedule Page: 300 Line No.: 4 Column: c

Includes \$18,052,199 in revenue related to the delivery of 665,844 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregon's electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2019, 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).

Schedule Page: 300 Line No.: 5 Column: b

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).

Schedule Page: 300 Line No.: 5 Column: c

Includes \$25,500,018 in revenue related to the delivery of 1,489,711 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2019, 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).

Schedule Page: 300 Line No.: 17 Column: b

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
Meter Verification Charges
Reconnect Charges
Returned Check Charges

Schedule Page: 300 Line No.: 17 Column: c

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
Portland General Electric Company			
FOOTNOTE DATA			

Meter Verification Charges
Reconnect Charges
Returned Check Charges

Schedule Page: 300 Line No.: 21 Column: b

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

Schedule Page: 300 Line No.: 21 Column: c

Other Electric Revenues consist of the following:	Q4-2019
2019 ETO Management	106,421
Boardman Decommissioning Balancing Account	(132,836)
Boardman Ops	176,527
Boardman Severance	(227,993)
Carty Major Maintenance Deferral	257,225
Colstrip - Major Maint Accrual/Defr	(2,795,622)
CSP Major Maintenance Deferral	3,146,462
Hydro License Implementation and Compliance	885,524
Lost Revenue Recovery	(1,115,160)
MCI Metro	5,121,090
Other	1,203,676
PW1 - Major Maint Deferral	(469,146)
PW2 - Major Maint Deferral	(181,982)
RPA Balancing	67,208,725

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2020/Q4
FOOTNOTE DATA			

Sch 7 Sales Norm Adj	(2,960,236)
Sch 83 Sales Norm Adj.	2,547,830
Steam Sales	1,874,091
Transport Electrification	7,085
Transmission Resale	6,997,356
Gas Resale	17,302,187
Grand Total	98,951,224

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
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10					
11					
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31					
32					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
- Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
- Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
- The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	(1) Residential					
2	6-Residential Pricing Pilot	-9	-1,022	1	-9,000	0.1136
3	7-Residential Service	7,708,344	962,437,119	791,118	9,744	0.1249
4	15-Outdoor Area Lighting	1,749	657,357			0.3758
5	(1) Residential Unbilled	46,167	6,816,000			0.1476
6	TOTAL Account 440	7,756,251	969,909,454	791,119	9,804	0.1250
7	(3) General Comm. & Ind.					
8	15-Outdoor Area Lighting	13,095	2,732,035			0.2086
9	32-Small Nonresidential	1,484,227	175,616,522	92,905	15,976	0.1183
10	38-Large Nonresidential	25,672	3,447,577	370	69,384	0.1343
11	47-Small Irrigation & Drainage	16,537	3,384,025	2,730	6,058	0.2046
12	49-Large Irrigation & Drainage	53,462	7,692,135	1,399	38,214	0.1439
13	83-Large Nonresidential	2,670,059	249,480,338	11,501	232,159	0.0934
14	85-Large Nonresidential	1,894,824	155,942,544	1,183	1,601,711	0.0823
15	89-Large Nonresidential	5,494	542,949	1	5,494,000	0.0988
16	485-Large Nonresidential COS O	4,523	336,359	3	1,507,667	0.0744
17	532-Small Nonresidential DAS	4	308			0.0770
18	583-Large Nonresidential DAS	73	3,493			0.0478
19	585-Large Nonresidential DAS		4,324			
20	(3) ESS General Comm. & Ind.					
21	83-Large Nonresidential			2		
22	485-Large Nonresidential COS O		11,857,141	226		
23	489-Large Nonresidential COS O		299,906	1		
24	515-Outdoor Area Lighting DAS		5,768			
25	532-Small Nonresidential DAS		430,896	174		
26	538-Large Nonresidential Opt.		2,862	2		
27	583-Large Nonresidential DAS		2,174,514	115		
28	585-Large Nonresidential DAS		3,433,074	42		
29	(3) General Comm. & Ind. Unbilled	5,402	1,789,000			0.3312
30	TOTAL Account 442 - Small	6,173,372	619,175,770	110,654	55,790	0.1003
31	(4) Large Ind. & Trans.					
32	89-Large Nonresidential	117,256	8,289,582	6	19,542,667	0.0707
33	(4) ESS Large Ind. & Trans.					
34	489-Large Nonresidential COS O		1,042,038	2		
35	(4) Large Ind. & Trans. Unbilled	1,787	76,000			0.0425
36	(5) Large Comm. & Ind.					
37	32-Small Nonresidential					
38	83-Large Nonresidential					
39	85-Large Nonresidential	610,007	45,896,358	170	3,588,276	0.0752
40	89-Large Nonresidential	420,115	27,495,597	12	35,009,583	0.0654
41	TOTAL Billed	17,340,180	1,835,464,453	902,237	19,219	0.1059
42	Total Unbilled Rev.(See Instr. 6)	83,623	10,618,000	0	0	0.1270
43	TOTAL	17,423,803	1,846,082,453	902,237	19,312	0.1060

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	90-Large Nonresidential	2,257,511	133,323,120	5	451,502,200	0.0591
2	485-Large Nonresidential COS O	1,864	129,097			0.0693
3	489-Large Nonresidential COS O	3,339	219,340			0.0657
4	689-New Large Load COS Opt-Out	219	11,002			0.0502
5	(5) ESS Large Comm. & Ind.					
6	485-Large Nonresidential COS		7,258,620	53		
7	489-Large Nonresidential COS O		18,752,339	14		
8	585-Large Nonresidential DAS		703,397	4		
9	689-New Large Load COS Opt-Out		51,794	1		
10	(5) Large Comm. & Ind. Unbilled	33,703	2,803,000			0.0832
11	TOTAL Account 442 - Large	3,445,801	246,051,284	267	12,905,622	0.0714
12	(6) Street Lighting					
13	91-Street & Hwy Lighting	24,000	6,682,606	180	133,333	0.2784
14	92-Traffic Signals	2,655	223,437	16	165,938	0.0842
15	95-Street & Hwy Lighting (New	25,161	4,905,902	1	25,161,000	0.1950
16	(6) Street Lighting Unbilled	-3,437	-866,000			0.2520
17	TOTAL Account 444	48,379	10,945,945	197	245,579	0.2263
18	Other Sales to Public Authorities					
19	TOTAL Account 445					
20	Sales to Railroads and Railways					
21	TOTAL Account 446					
22	Interdepartmental Sales					
23	TOTAL Account 448					
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	17,340,180	1,835,464,453	902,237	19,219	0.1059
42	Total Unbilled Rev.(See Instr. 6)	83,623	10,618,000	0	0	0.1270
43	TOTAL	17,423,803	1,846,082,453	902,237	19,312	0.1060

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Avangrid Renewables (was Iberdrola)	SF	EEI	NA	NA	NA
2	Avista Corp.	SF	WSPP-1	NA	NA	NA
3	BP Energy Company	SF	PGE-11	NA	NA	NA
4	Black Hills Power	SF	WSPP-1	NA	NA	NA
5	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
6	British Columbia Hydro & Power Authority	SF	WSPP-1	NA	NA	NA
7	Brookfield Energy Marketing LP	SF	WSPP-1	NA	NA	NA
8	California Independent System Operator	SF	CAISO	NA	NA	NA
9	Calpine Energy Services, L.P.	SF	EEI	NA	NA	NA
10	Calpine Energy Services, L.P.	OS	WSPP-1	NA	NA	NA
11	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
12	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
13	City of Burbank	SF	WSPP-1	NA	NA	NA
14	City of Glendale	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Element Markets	OS	EEI	NA	NA	NA
2	Energy Keepers, Inc.	SF	WSPP-1	NA	NA	NA
3	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
4	Exelon Generation Company, LLC	SF	EEI	NA	NA	NA
5	Gridforce Energy Management	SF	WSPP-1	NA	NA	NA
6	Idaho Power Company	SF	WSPP-1	NA	NA	NA
7	Load Balance Energy	OS	OATT	NA	NA	NA
8	Los Angeles Dept. Water Power	SF	WSPP-1	NA	NA	NA
9	Los Angeles Dept. Water Power	OS	WSPP-1	NA	NA	NA
10	Macquarie Energy LLC	SF	WSPP-1	NA	NA	NA
11	Morgan Stanley Capital Group, Inc.	SF	PGE-11	NA	NA	NA
12	NaturEner Power Watch, LLC	SF	WSPP-1	NA	NA	NA
13	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
14	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PacifiCorp	SF	EEI	NA	NA	NA
2	PacifiCorp	LU	PGE-11	NA	NA	NA
3	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
4	Powerex Corp.	SF	EEI	NA	NA	NA
5	Pend Orielle County PUD	SF	WSPP-1	NA	NA	NA
6	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
7	Public Utility District No. 1 of Okanoy	SF	WSPP-1	NA	NA	NA
8	Public Utility District No. 2 of Granty	SF	WSPP-1	NA	NA	NA
9	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
10	Rainbow Energy Marketing Company	SF	WSPP-1	NA	NA	NA
11	San Diego Gas & Electric	SF	WSPP-1	NA	NA	NA
12	San Jose Clean Energy	OS	WSPP-1	NA	NA	NA
13	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
14	Sacramento Municipal Utility District	OS	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Seattle City Light	SF	WSPP-1	NA	NA	NA
2	Shell Energy North America (US), L.P.	SF	PGE-11	NA	NA	NA
3	Snohomish County, PUD No.1, Washington	SF	WSPP-1	NA	NA	NA
4	Southern California Edison	SF	EEI	NA	NA	NA
5	Tacoma Power	SF	WSPP-1	NA	NA	NA
6	Tenaska Power Services Co.	SF	WSPP-1	NA	NA	NA
7	The Energy Authority, Inc.	SF	WSPP-1	NA	NA	NA
8	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI	NA	NA	NA
9	TransCanada Energy Sales Ltd.	SF	WSPP-1	NA	NA	NA
10	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
11	Vitol Inc.	SF	WSPP-1	NA	NA	NA
12	Wheatridge Wind II, LLC	LU	WSPP-1	NA	NA	NA
13	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Direct Access deferral 2020			NA	NA	NA
2	Direct Access amortization 2020			NA	NA	NA
3						
4	Non-RQ Sales:					
5						
6	Portland General Electric Company	SF	OA96137	926	NA	NA
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
218,061		6,043,017		6,043,017	1
30,665		871,269		871,269	2
52,636		1,116,766		1,116,766	3
13,493		1,302,389		1,302,389	4
192,049		4,603,034		4,603,034	5
37		866		866	6
2,640		66,162		66,162	7
2,773,488		55,590,215		55,590,215	8
14,530		459,618		459,618	9
			716,172	716,172	10
7		106		106	11
9,537		1,363,572		1,363,572	12
2,305		80,360		80,360	13
2,643		70,250		70,250	14
0	0	0	0	0	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
			916,050	916,050	1
			573,500	573,500	2
5,950		155,325		155,325	3
218,775		9,497,921		9,497,921	4
848		24,041		24,041	5
			657,155	657,155	6
182,785		4,532,393		4,532,393	7
33,105		1,564,207		1,564,207	8
			362,500	362,500	9
168,700		47,679		47,679	10
100,606		2,884,426		2,884,426	11
			42,560	42,560	12
			2,980,790	2,980,790	13
24,003		689,560		689,560	14
0	0	0	0	0	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
			544,501	544,501	1
321,815		8,868,127		8,868,127	2
19,526		402,202		402,202	3
41,226		909,256		909,256	4
257		6,069		6,069	5
32,425		507,828		507,828	6
32,546					7
33,055		1,089,528		1,089,528	8
			363,605	363,605	9
91,838		2,259,769		2,259,769	10
75,288		2,802,691		2,802,691	11
224		5,309		5,309	12
3,356		86,562		86,562	13
51,449		1,391,076		1,391,076	14
0	0	0	0	0	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
79,076		2,296,467		2,296,467	1
17,020		116,628		116,628	2
109,150		3,313,138		3,313,138	3
46,016		1,008,046		1,008,046	4
188,155		3,230,693		3,230,693	5
400		7,900		7,900	6
1,408		66,920		66,920	7
228,357		6,926,774		6,926,774	8
167,934		5,964,564		5,964,564	9
2,236		58,745		58,745	10
9,995		414,793		414,793	11
			6,914,137	6,914,137	12
4,626		738,772		738,772	13
			4,068,336	4,068,336	14
0	0	0	0	0	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
22,873		616,775		616,775	1
63,715		1,589,730		1,589,730	2
19,790		504,048		504,048	3
214,879		11,922,556		11,922,556	4
40,497		1,064,191		1,064,191	5
252,214		4,826,129		4,826,129	6
48,884		1,419,318		1,419,318	7
102,255		2,738,304		2,738,304	8
60,199		1,146,691		1,146,691	9
10,239		431,940		431,940	10
2,000		50,036		50,036	11
		-1,045,524		-1,045,524	12
794		28,995		28,995	13
					14
0	0	0	0	0	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
			-400,320	-400,320	1
			1,062,379	1,062,379	2
					3
					4
					5
	7,067,263			7,067,263	6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	
6,442,580	7,067,263	158,728,222	18,801,365	184,596,850	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 10 Column: j

Represents sales of renewable energy credits to Calpine.

Schedule Page: 310.1 Line No.: 1 Column: j

Represents sales of renewable energy credits to City of Corona

Schedule Page: 310.1 Line No.: 2 Column: j

Represents sales of renewable energy credits to City of Industry

Schedule Page: 310.1 Line No.: 6 Column: j

Represents sales of renewable energy credits to Clean Power Alliance

Schedule Page: 310.1 Line No.: 9 Column: j

Represents sales of renewable energy credits to Direct Business Energy Marketing

Schedule Page: 310.1 Line No.: 12 Column: j

Represents sales of renewable energy credits to Desert Community Energy

Schedule Page: 310.1 Line No.: 13 Column: jRepresents sales of renewable energy credits to
EAST BAY COMMUNITY ENERGY AUTHORITY**Schedule Page: 310.2 Line No.: 1 Column: j**

Represents sales of renewable energy credits to Element Market

Schedule Page: 310.2 Line No.: 9 Column: j

Represents sales of renewable energy credits to Los Angeles Dept. Water Power

Schedule Page: 310.3 Line No.: 2 Column: b

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

Schedule Page: 310.3 Line No.: 12 Column: j

Represents sales of renewable energy credits to San Jose Clean Energy

Schedule Page: 310.3 Line No.: 14 Column: j

Represents sales of renewable energy credits to Sacramento Municipal Utility District

Schedule Page: 310.4 Line No.: 12 Column: i

Wheatridge II Test Energy reclassified to capital

Schedule Page: 310.5 Line No.: 1 Column: jDefer costs associated with the implementation of the annual
direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.**Schedule Page: 310.5 Line No.: 2 Column: j**Amortization of deferred costs associated with the implementation of the annual
direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.**Schedule Page: 310.5 Line No.: 6 Column: a**Represents Portland General Electric Company's use of Portland
General Electric Company's Open Access Transmission
System. This is included in Account 447 based on guidance
from FERC Deputy Chief Accountant - issued January 1996.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,351,045	2,330,701
5	(501) Fuel	70,676,152	93,517,673
6	(502) Steam Expenses	15,834,155	8,506,261
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	7,903,659	11,103,441
11	(507) Rents		16,802
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	96,765,011	115,474,878
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	964,898	901,629
16	(511) Maintenance of Structures	993,652	1,099,748
17	(512) Maintenance of Boiler Plant	8,181,488	6,475,812
18	(513) Maintenance of Electric Plant	5,096,511	7,623,269
19	(514) Maintenance of Miscellaneous Steam Plant	836,609	936,102
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	16,073,158	17,036,560
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	112,838,169	132,511,438
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	787,010	924,616
45	(536) Water for Power	608,858	603,680
46	(537) Hydraulic Expenses	7,149,131	7,127,838
47	(538) Electric Expenses	1,701,819	1,630,458
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,375,138	4,037,198
49	(540) Rents	809,334	777,790
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	14,431,290	15,101,580
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	994,464	753,270
54	(542) Maintenance of Structures	4,894	
55	(543) Maintenance of Reservoirs, Dams, and Waterways	362,086	1,263,061
56	(544) Maintenance of Electric Plant	1,355,885	1,313,156
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,580,035	1,077,945
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,297,364	4,407,432
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	18,728,654	19,509,012

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,369,465	3,719,373
63	(547) Fuel	170,765,398	194,396,475
64	(548) Generation Expenses	8,506,242	8,894,822
65	(549) Miscellaneous Other Power Generation Expenses	13,416,046	19,499,593
66	(550) Rents	944,505	1,000,732
67	TOTAL Operation (Enter Total of lines 62 thru 66)	197,001,656	227,510,995
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,686,939	1,860,170
70	(552) Maintenance of Structures	292,574	534,328
71	(553) Maintenance of Generating and Electric Plant	30,378,456	44,669,783
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,037,697	1,097,144
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	33,395,666	48,161,425
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	230,397,322	275,672,420
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	418,799,466	281,457,582
77	(556) System Control and Load Dispatching	238,013	250,780
78	(557) Other Expenses	21,170,453	22,883,439
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	440,207,932	304,591,801
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	802,172,077	732,284,671
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,440,319	7,644,678
84			
85	(561.1) Load Dispatch-Reliability	16,150	14,627
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,053,301	961,011
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,400,410	1,512,133
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		8,813
91	(561.7) Generation Interconnection Studies	195,430	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	290,541	206,486
94	(563) Overhead Lines Expenses	313,338	175,946
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	81,280,168	83,561,883
97	(566) Miscellaneous Transmission Expenses	2,975,438	7,315,275
98	(567) Rents	2,908,566	3,574,527
99	TOTAL Operation (Enter Total of lines 83 thru 98)	97,873,661	104,975,379
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	10,247	20,563
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	748,322	821,808
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,565,923	1,436,260
108	(571) Maintenance of Overhead Lines	1,326,886	1,299,193
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	778	3,483
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,652,156	3,581,307
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	101,525,817	108,556,686

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
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 Op Exps (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	17,715,664	26,332,943
135	(581) Load Dispatching	2,687,850	2,512,422
136	(582) Station Expenses	812,703	961,036
137	(583) Overhead Line Expenses	2,927,260	2,519,942
138	(584) Underground Line Expenses	4,218,614	3,648,832
139	(585) Street Lighting and Signal System Expenses	235,512	380,005
140	(586) Meter Expenses	2,292,043	3,086,554
141	(587) Customer Installations Expenses	3,021,147	3,885,491
142	(588) Miscellaneous Expenses	10,605,286	9,300,372
143	(589) Rents	1,687,489	1,978,035
144	TOTAL Operation (Enter Total of lines 134 thru 143)	46,203,568	54,605,632
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	37,138	44,098
147	(591) Maintenance of Structures	172,665	230,487
148	(592) Maintenance of Station Equipment	4,835,898	5,711,135
149	(593) Maintenance of Overhead Lines	55,034,683	51,687,071
150	(594) Maintenance of Underground Lines	8,069,382	9,429,811
151	(595) Maintenance of Line Transformers	1,881,127	2,571,576
152	(596) Maintenance of Street Lighting and Signal Systems	947,941	1,255,633
153	(597) Maintenance of Meters	5,790	51,996
154	(598) Maintenance of Miscellaneous Distribution Plant	6,817,818	9,030,454
155	TOTAL Maintenance (Total of lines 146 thru 154)	77,802,442	80,012,261
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	124,006,010	134,617,893
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	352,224	398,441
161	(903) Customer Records and Collection Expenses	50,657,698	55,772,614
162	(904) Uncollectible Accounts	7,069,010	2,155,688
163	(905) Miscellaneous Customer Accounts Expenses	5,547,635	6,944,625
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	63,626,567	65,271,368

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	14,614,122	13,156,211
169	(909) Informational and Instructional Expenses	1,821,001	1,560,301
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	16,435,123	14,716,512
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	80,315,704	81,318,578
182	(921) Office Supplies and Expenses	17,790,843	23,059,355
183	(Less) (922) Administrative Expenses Transferred-Credit	12,633,527	12,888,110
184	(923) Outside Services Employed	13,849,356	8,843,144
185	(924) Property Insurance	6,911,324	6,659,426
186	(925) Injuries and Damages	4,107,996	5,454,493
187	(926) Employee Pensions and Benefits	57,727,595	62,501,938
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	10,485,584	10,439,272
190	(929) (Less) Duplicate Charges-Cr.	2,325,928	2,769,908
191	(930.1) General Advertising Expenses	1,045,923	1,298,824
192	(930.2) Miscellaneous General Expenses	20,720,146	18,431,722
193	(931) Rents	3,914,762	4,604,944
194	TOTAL Operation (Enter Total of lines 181 thru 193)	201,909,778	206,953,678
195	Maintenance		
196	(935) Maintenance of General Plant	2,785,844	3,295,290
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	204,695,622	210,248,968
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,312,461,216	1,265,696,098

Document Accession #: 20210420-8026 PURCHASED POWER (Account 555) (Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Arizona Public	SF	WSPP-1	NA	NA	NA
2	Airport Solar, LLC	LU	201	NA	NA	NA
3	Alkali Solar	LU	201	NA	NA	NA
4	Avangrid Renewables (was Iberdrola)	SF	PGE-11	NA	NA	NA
5	Avangrid Renewables (was berdrola Ren)	LU	PGE-11	NA	NA	NA
6	Avangrid Renewables (was Iberdrola)	LU	PGE-11	NA	NA	NA
7	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
8	BP Energy Company	SF	PGE-11	NA	NA	NA
9	Ballston Solar	LU	201	NA	NA	NA
10	Bellevue Solar	LU	Bellevue	NA	NA	NA
11	Black Hills Power	SF	WSPP-1	NA	NA	NA
12	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
13	Boring Solar	LU	201	NA	NA	NA
14	Brookfield Energy Marketing	SF	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
2	California Independent System Operator	SF	CAISO	NA	NA	NA
3	Calpine Energy Services	SF	PGE-11	NA	NA	NA
4	Case Creek Solar	LU	201	NA	NA	NA
5	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
6	Citigroup Energy	SF	WSPP-1	NA	NA	NA
7	Burbank, City of	SF	WSPP-1	NA	NA	NA
8	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
9	ConocoPhillips	SF	WSPP-1	NA	NA	NA
10	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
11	Covanta Marion	LU	QF83-118	NA	NA	NA
12	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
13	Douglas County, PUD No. 1, Washington	LF	WSPP-1	NA	NA	NA
14	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
	Total					

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

**PURCHASED POWER (Account 555)
(Including power exchanges)**

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
2	DTE Energy Trading, Inc.	SF	WSPP-1	NA	NA	NA
3	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
4	Enmax	SF	PGE-11	NA	NA	NA
5	Energy Keepers, Inc. - ENKP	SF	WSPP-1	NA	NA	NA
6	ESI Vansycle Partners, LP	LU	WSPP-1	NA	NA	NA
7	Eugene Water & Electric Board	LU	WSPP-1	NA	NA	NA
8	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
9	Evergreen Biomass	LU	201	NA	NA	NA
10	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
11	Falls Creek Hydro	LU	201	NA	NA	NA
12	Fort Rock Solar 1	LU	201	NA	NA	NA
13	Fort Rock Solar 4	LU	201	NA	NA	NA
14	Firwood Solar	LU	201	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Garrett Solar LLC	LU	201	NA	NA	NA
2	Gridforce Energy Management - GRID	SF	WSPP-1	NA	NA	NA
3	Idaho Power Company	SF	WSPP-1	NA	NA	NA
4	Labish Solar	LU	201	NA	NA	NA
5	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
6	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
7	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
8	Nevada Power Company	SF	WSPP-1	NA	NA	NA
9	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
10	NextEra Energy Power Marketing, LLC	LF	WSPP-1	NA	NA	NA
11	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
12	NorthWestern Corporation	OS	WSPP-1	NA	NA	NA
13	Northwestern Energy	SF	WSPP-1	NA	NA	NA
14	Norwest Energy 14	LU	201	NA	NA	NA
	Total					

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Obsidian Lakeview	LU	201	NA	NA	NA
2	OE Solar 3, LLC	LU	201	NA	NA	NA
3	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
4	Okanogan County PUD, Washington	LU	WSPP-1	NA	NA	NA
5	Okanogan County PUD, Washington	LF	WSPP-1	NA	NA	NA
6	O'Neil Solar	LU	201	NA	NA	NA
7	Outback Solar	LU	Outback	NA	NA	NA
8	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
9	PacifiCorp	SF	PGE-11	NA	NA	NA
10	PaTu Wind	LU	WSPP-1	NA	NA	NA
11	Duus Solar (Alchemy)	LU	201	NA	NA	NA
12	Portland, City of	LU	#2821	NA	NA	NA
13	Powerex	SF	PGE-11	NA	NA	NA
14	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
	Total					

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
2	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
3	Pend Orielle County PUD	SF	WSPP-1	NA	NA	NA
4	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
5	Rafael Solar	LU	201	NA	NA	NA
6	Riley Solar	LU	201	NA	NA	NA
7	Rock Garden Solar	LU	201	NA	NA	NA
8	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
9	Seattle City Light	SF	WSPP-1	NA	NA	NA
10	Shell Energy	SF	WSPP-1	NA	NA	NA
11	Sheep Solar	LU	201	NA	NA	NA
12	Silverton Solar	LU	201	NA	NA	NA
13	Snohomish County, PUD No. 1, Washingn	SF	WSPP-1	NA	NA	NA
14	SP Solar 1, LLC	LU	201	NA	NA	NA
	Total					

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

**PURCHASED POWER (Account 555)
(Including power exchanges)**

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1	SP Solar 5, LLC	LU	201	NA	NA	NA
2	SP Solar 6, LLC	LU	201	NA	NA	NA
3	SP Solar 7, LLC	LU	201	NA	NA	NA
4	SP Solar 8, LLC	LU	201	NA	NA	NA
5	Steel Bridge	LU	201	NA	NA	NA
6	Starvation Solar 1 LLC	LU	201	NA	NA	NA
7	St Louis Solar	LU	201	NA	NA	NA
8	Suluss Solar 35	LU	201	NA	NA	NA
9	Suluss Solar 17	LU	201	NA	NA	NA
10	Suntex Solar	LU	201	NA	NA	NA
11	West Hines Solar	LU	201	NA	NA	NA
12	Tacoma, City of	SF	WSPP-1	NA	NA	NA
13	Tenaska Power Services	SF	WSPP-1	NA	NA	NA
14	Tenaska Power Services	SF	WSPP-1	NA	NA	NA
	Total					

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	The Energy Authority	SF	WSPP-1	NA	NA	NA
2	Thomas Creek Solar	LU	201	NA	NA	NA
3	Tickle Creek	LU	201	NA	NA	NA
4	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
5	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
6	Tri-State Generation	SF	WSPP-1	NA	NA	NA
7	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
8	Vitol Inc.	SF	WSPP-1	NA	NA	NA
9	Volcano Solar	LU	201	NA	NA	NA
10	VON FAMILY LTD PARTNERSHIP	LU	201	NA	NA	NA
11	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
12	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
13	Wheatridge Wind II, LLC	LU	WSPP-1	NA	NA	NA
14	Kale Patch Solar	LU	201	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Drift Creek	LU	201	NA	NA	NA
2	Yamhill Solar	LU	Yamhill	NA	NA	NA
3	Load Balance Energy	OS	OATT	NA	NA	NA
4	Country Village Estates	OS	201	NA	NA	NA
5	Domaine Drouhin	OS	201	NA	NA	NA
6	Lake Oswego Corporation	OS	201	NA	NA	NA
7	Minikahada Hydropower Co	OS	201	NA	NA	NA
8	Starbuck Properties	OS	201	NA	NA	NA
9	Solar Payment Option	OS	215-217	NA	NA	NA
10	Tualatin Valley Water Dist	OS	201	NA	NA	NA
11	Oregon Energy Fund	OS	203	NA	NA	NA
12	Green Power			NA	NA	NA
13	NVPC MONET QF Deferrals			NA	NA	NA
14	Margin on Electric Financials			NA	NA	NA
	Total					

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

PURCHASED POWER (Account 555)
(Including power exchanges)

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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Load Curtailment Program			NA	NA	NA
2	Reserve Trading Credit Risk			NA	NA	NA
3	REC Retirement Expense			NA	NA	NA
4	Carbon Allowance Expense			NA	NA	NA
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
20,000				1,780,000		1,780,000	1
103,807				7,692,324		7,692,324	2
16,919				1,465,490		1,465,490	3
487,362				11,016,464		11,016,464	4
187,312				11,901,911		11,901,911	5
			3,120,000			3,120,000	6
33,525				1,635,752		1,635,752	7
253,352				2,644,274		2,644,274	8
2,321				337,685		337,685	9
1,389				202,853		202,853	10
50				2,000		2,000	11
1,402,347				19,067,944		19,067,944	12
2,150				345,007		345,007	13
11,412				151,690		151,690	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
225				9,450		9,450	1
604,789				7,862,237		7,862,237	2
344,724				7,583,924		7,583,924	3
				303,238		303,238	4
104,910				1,022,095		1,022,095	5
159,559				6,683,176		6,683,176	6
800				28,000		28,000	7
4,337				55,803		55,803	8
1,308,557				29,684,946		29,684,946	9
				71,696		71,696	10
80,367				1,484,843		1,484,843	11
1,030,432				23,330,563		23,330,563	12
				1,882,051		1,882,051	13
7,865				1,463,879		1,463,879	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
			1,200,000			1,200,000	1
1,800				8,050		8,050	2
20,892				1,723,515		1,723,515	3
225				9,750		9,750	4
805				28,597		28,597	5
76,884				5,589,811		5,589,811	6
			84,000			84,000	7
23,923				475,298		475,298	8
46,910				4,308,178		4,308,178	9
67,938				1,205,234		1,205,234	10
16,428				1,217,641		1,217,641	11
22,747				1,922,418		1,922,418	12
16,424				1,328,879		1,328,879	13
20,602							14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				58,711		58,711	1
13				458		458	2
47,331				571,748		571,748	3
2,296				282,387		282,387	4
400				13,800		13,800	5
89,400				1,372,799		1,372,799	6
44,410				873,999		873,999	7
8,400				361,200		361,200	8
29,819				84,653		84,653	9
60,494				1,303,306		1,303,306	10
35,410				188,339		188,339	11
-50,707							12
24				433,904		433,904	13
3,762				380,681		380,681	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
23,837				2,130,805		2,130,805	1
25,020				1,559,135		1,559,135	2
5,084				390,952		390,952	3
			130,000			130,000	4
				361,908		361,908	5
2,192				343,281		343,281	6
10,368				979,539		979,539	7
65,096				3,696,074		3,696,074	8
36,179				1,673,328		1,673,328	9
32,515				2,694,537		2,694,537	10
				3,228,264		3,228,264	11
86,925				2,355,819		2,355,819	12
109,335				3,593,694		3,593,694	13
397,458				11,946,035		11,946,035	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

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397,458				11,946,035		11,946,035	1
97,641				2,674,143		2,674,143	2
416,353				10,650,395		10,650,395	3
307,121				7,141,340		7,141,340	4
2,224				309,816		309,816	5
12,440				1,059,150		1,059,150	6
15,396				1,330,053		1,330,053	7
100				3,650		3,650	8
219,290				5,557,298		5,557,298	9
148,677				2,403,750		2,403,750	10
3,896				348,720		348,720	11
3,815				335,141		335,141	12
93,675				1,356,257		1,356,257	13
3,894				351,801		351,801	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
3,946				376,860		376,860	1
3,064				331,933		331,933	2
3,064				336,780		336,780	3
3,894				369,487		369,487	4
3,292				280,008		280,008	5
25,743				2,213,596		2,213,596	6
				269,190		269,190	7
				61,729		61,729	8
				72,549		72,549	9
13,561				1,175,491		1,175,491	10
16,070				1,391,218		1,391,218	11
129,666				2,230,475		2,230,475	12
20,722				808,573		808,573	13
				-73,955		-73,955	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
88,538				1,369,805		1,369,805	1
2,342				282,807		282,807	2
1,803				198,629		198,629	3
156,829				3,140,935		3,140,935	4
200				11,335		11,335	5
1				24		24	6
49,360				429,652		429,652	7
3,600				71,300		71,300	8
743				94,226		94,226	9
252				13,176		13,176	10
430,064				9,257,607		9,257,607	11
			4,000,000			4,000,000	12
43,059				1,445,054		1,445,054	13
2,328				273,206		273,206	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				390,029		390,029	1
1,105				62,170		62,170	2
64,208							3
				167		167	4
103				9,273		9,273	5
180				17,056		17,056	6
143				9,603		9,603	7
18				1,658		1,658	8
18,719				263,441		263,441	9
284				19,769		19,769	10
					121,502	121,502	11
					16,225,182	16,225,182	12
					3,902,221	3,902,221	13
					122,228,935	122,228,935	14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					-3,300	-3,300	1
					38,098	38,098	2
					635,544	635,544	3
					-3,961,143	-3,961,143	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
10,358,031			8,460,045	271,152,382	139,187,039	418,799,466	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 326.1 Line No.: 12 Column: b

The Douglas County contract expires on 9/30/28.

Schedule Page: 326.1 Line No.: 13 Column: b

The 2020 Douglas County contract expires on 12/31/2025.

Schedule Page: 326.3 Line No.: 10 Column: b

The NextEra contract expires on 12/3/2050

Schedule Page: 326.3 Line No.: 12 Column: b

Colstrip Nonrunning Loss (station services)

Schedule Page: 326.4 Line No.: 5 Column: b

The 2020 Okanogan County contract expires on 12/31/2025.

Schedule Page: 326.8 Line No.: 3 Column: a

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

Schedule Page: 326.8 Line No.: 4 Column: b

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

Schedule Page: 326.8 Line No.: 5 Column: b

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

Schedule Page: 326.8 Line No.: 6 Column: b

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

Schedule Page: 326.8 Line No.: 7 Column: b

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

Schedule Page: 326.8 Line No.: 8 Column: b

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

Schedule Page: 326.8 Line No.: 9 Column: b

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

Schedule Page: 326.8 Line No.: 10 Column: b

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

Schedule Page: 326.8 Line No.: 11 Column: b

In accordance with Schedule 203, 215, 216(b) tariff any excess credits will be transferred to Low Income Assistance Program.

Schedule Page: 326.8 Line No.: 12 Column: I

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

Schedule Page: 326.8 Line No.: 13 Column: I

2020 NVPC MONET QF Deferrals & Cure Payments

Schedule Page: 326.8 Line No.: 14 Column: I

Margin on electric financial transactions.

Schedule Page: 326.9 Line No.: 1 Column: I

Load Curtailment Program.

Schedule Page: 326.9 Line No.: 2 Column: I

Reserve for trading credit risk.

Schedule Page: 326.9 Line No.: 3 Column: I

Expense of annual REC retirement to meet RPS compliance.

Schedule Page: 326.9 Line No.: 4 Column: I

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

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

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
 2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
 3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
 4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	BPA Power Business Line	Bonneville Power Administration	West Oregon Electric Coop Total	OLF
2	BPA Power Business Line	Bonneville Power Administration	Other TVI Pumps Total	OLF
3	BPA Power Business Line	Bonneville Power Administration	Canby PUD Total	OLF
4	BPA Power Business Line	Bonneville Power Administration	Columbia River PUD Total	OLF
5	Pacificorp West	PacifiCorp	Portland General Electric	OLF
6	3 Phases Renewables LLC	Bonneville Power Administration	Oregon Direct Access	FNO
7	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO
8	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO
9	BPA Power Business Line			OS
10	Calpine Energy Services	Bonneville Power Administration	Oregon Direct Access	FNO
11	Constellation New Energy	Bonneville Power Administration	Oregon Direct Access	FNO
12	Shell Energy North America	Bonneville Power Administration	Oregon Direct Access	FNO
13	Avista Corp	Bonneville Power Administration	Balancing Authority of Northern C	LFP
14	Avista Corp	Bonneville Power Administration	California Independent System Ope	LFP
15	Avista Corp	California Independent System Ope	Bonneville Power Administration	NF
16	Avista Corp	California Independent System Ope	Bonneville Power Administration	OS
17	Avista Corp			OS
18	BPA Power Business Line	Bonneville Power Administration	California Independent System Ope	NF
19	Brookfield Renewable Trading and Marketing	Bonneville Power Administration	California Independent System Ope	NF
20	Brookfield Renewable Trading and Marketing			OS
21	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern C	LFP
22	Shell Energy North America	Bonneville Power Administration	California Independent System Ope	LFP
23	Shell Energy North America	Bonneville Power Administration	California Independent System Ope	LFP
24	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern C	NF
25	Shell Energy North America	Bonneville Power Administration	California Independent System Ope	NF
26	Shell Energy North America	Bonneville Power Administration	Portland General Electric	NF
27	Shell Energy North America	California Independent System Ope	Bonneville Power Administration	OS
28	Shell Energy North America			OS
29	Constellation New Energy	Bonneville Power Administration	California Independent System Ope	LFP
30	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern C	LFP
31	Constellation New Energy	Bonneville Power Administration	Portland General Electric	LFP
32	Constellation New Energy	Bonneville Power Administration	California Independent System Ope	NF
33	Constellation New Energy			OS
34	Macquarie Energy LLC	Bonneville Power Administration	California Independent System Ope	NF
	TOTAL			

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
 2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
 3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
 4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	Macquarie Energy LLC			OS
2	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern C	LFP
3	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Ope	LFP
4	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern C	NF
5	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Ope	NF
6	Morgan Stanley Capital Group	California Independent System Ope	Bonneville Power Administration	NF
7	Morgan Stanley Capital Group	California Independent System Ope	Bonneville Power Administration	OS
8	Morgan Stanley Capital Group			OS
9	Pacificorp West	Portland General Electric	Bonneville Power Administration	LFP
10	Pacificorp West	Portland General Electric	Bonneville Power Administration	NF
11	Pacificorp West			OS
12	Avangrid Renewables, LLC	Bonneville Power Administration	Balancing Authority of Northern C	NF
13	Avangrid Renewables, LLC	Bonneville Power Administration	California Independent System Ope	NF
14	Avangrid Renewables, LLC	Bonneville Power Administration	Bonneville Power Administration	NF
15	Avangrid Renewables, LLC			OS
16	Puget Sound Energy	Bonneville Power Administration	Balancing Authority of Northern C	NF
17	Puget Sound Energy	Bonneville Power Administration	California Independent System Ope	NF
18	Puget Sound Energy			OS
19	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	LFP
20	Powerex Inc.	Bonneville Power Administration	California Independent System Ope	LFP
21	Powerex Inc.	California Independent System Ope	Bonneville Power Administration	LFP
22	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	NF
23	Powerex Inc.	Bonneville Power Administration	California Independent System Ope	NF
24	Powerex Inc.	California Independent System Ope	Bonneville Power Administration	NF
25	Powerex Inc.	California Independent System Ope	Bonneville Power Administration	OS
26	Powerex Inc.			OS
27	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern C	NF
28	Seattle City Light			OS
29	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern C	LFP
30	The Energy Authority	Bonneville Power Administration	California Independent System Ope	LFP
31	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern C	NF
32	The Energy Authority	Bonneville Power Administration	California Independent System Ope	NF
33	The Energy Authority	California Independent System Ope	Bonneville Power Administration	NF
34	The Energy Authority	California Independent System Ope	Bonneville Power Administration	OS
	TOTAL			

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	The Energy Authority			OS
2	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	Balancing Authority of Northern C	NF
3	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	California Independent System Ope	NF
4	Transalta Energy Marketing (US) Inc.	California Independent System Ope	Bonneville Power Administration	NF
5	Transalta Energy Marketing (US) Inc.			OS
6	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of Northern C	NF
7	Turlock Irrigation District			OS
8	Tacoma Power	Bonneville Power Administration	California Independent System Ope	NF
9	Tacoma Power			OS
10	Public Utility District No. 1 of Cowlitz Count	Bonneville Power Administration	California Independent System Ope	LFP
11	Public Utility District No. 1 of Franklin Coun	Bonneville Power Administration	California Independent System Ope	LFP
12	Public Utility District No. 1 of Klickitat Cou	Bonneville Power Administration	California Independent System Ope	LFP
13	Public Utility District No. 1 of Lewis County	Bonneville Power Administration	California Independent System Ope	LFP
14	Accrual			AD
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
 (Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
72	BPAT.PGE	Various		13,196	13,078	1
72	BPAT.PGE	Various		6,824	6,763	2
72	BPAT.PGE	Various		185,208	183,558	3
72	BPAT.PGE	Various		171,171	169,647	4
Exchange	PACW.PGE	Various		3,901	3,908	5
7	BPAT.PGE	Various	15	8,783	8,783	6
7	BPAT.PGE	Various	300	114,163	114,163	7
7	BPAT.PGE	Various Subs	126	78,372	78,372	8
11						9
7	BPAT.PGE	Various	2,512	1,455,353	1,455,353	10
7	BPAT.PGE	Various	922	461,202	461,202	11
7	BPAT.PGE	Various	375	225,983	225,983	12
7	JohnDay	CaptainJack		5,571	5,571	13
7	JohnDay	Malin500		382,944	382,944	14
8	Malin500	JohnDay		200	200	15
8	Malin500	JohnDay		525	525	16
11						17
8	JohnDay	Malin500		97	97	18
8	JohnDay	Malin500		2,125	2,125	19
11						20
7	JohnDay	CaptainJack		538,656	538,656	21
7	JohnDay	COBH		188	188	22
7	JohnDay	Malin500		766,582	766,582	23
8	JohnDay	CaptainJack		9,417	9,417	24
8	JohnDay	Malin500		59,294	59,294	25
8	BPAT.PGE	PGE		32	32	26
8	Malin500	JohnDay		923	923	27
11						28
7	JohnDay	Malin500		70,012	70,012	29
7	JohnDay	CaptainJack		474	474	30
7	BPAT.PGE	PGE		64	64	31
8	JohnDay	Malin500		1,157	1,157	32
11						33
8	JohnDay	Malin500		323	323	34
			4,250	6,818,609	6,815,263	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
11						1
7	JohnDay	CaptainJack		123,807	123,807	2
7	JohnDay	Malin500		58,000	58,000	3
8	JohnDay	CaptainJack		7,364	7,364	4
8	JohnDay	Malin500		7,580	7,580	5
8	Malin500	JohnDay		30	30	6
8	Malin500	JohnDay		34	34	7
11						8
7	RoundButte	REDMOND		15,190	15,190	9
8	RoundButte	REDMOND		883	883	10
11						11
8	JohnDay	CaptainJack		11	11	12
8	JohnDay	Malin500		113	113	13
8	KFallsGen	JohnDay		839	839	14
11						15
8	JohnDay	CaptainJack		141	141	16
8	JohnDay	Malin500		332	332	17
11						18
7	JohnDay	CaptainJack		94,021	94,021	19
7	JohnDay	Malin500		1,482,919	1,482,919	20
7	Malin500	JohnDay		208,347	208,347	21
8	JohnDay	CaptainJack		2,355	2,355	22
8	JohnDay	Malin500		3,234	3,234	23
8	Malin500	JohnDay		1,951	1,951	24
8	Malin500	JohnDay		25	25	25
11						26
8	JohnDay	CaptainJack		669	669	27
11						28
7	JohnDay	CaptainJack		37,725	37,725	29
7	JohnDay	Malin500		186,488	186,488	30
8	JohnDay	CaptainJack		1,771	1,771	31
8	JohnDay	Malin500		3,646	3,646	32
8	Malin500	JohnDay		1,848	1,848	33
8	Malin500	JohnDay		329	329	34
			4,250	6,818,609	6,815,263	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
11						1
8	JohnDay	CaptainJack		3,264	3,264	2
8	JohnDay	Malin500		12,122	12,122	3
8	Malin500	JohnDay		743	743	4
11						5
8	JohnDay	CaptainJack		87	87	6
11						7
8	JohnDay	Malin500		1	1	8
11						9
7	JohnDay	COBH				10
7	JohnDay	COBH				11
7	JohnDay	COBH				12
7	JohnDay	COBH				13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			4,250	6,818,609	6,815,263	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
		90,848	90,848	1
		26,249	26,249	2
		368,928	368,928	3
		24,853	24,853	4
		247,328	247,328	5
5,763	-93,160	4,079	-83,318	6
113,938	62,013	72,323	248,274	7
33,130	-160,280	51,833	-75,317	8
	27,586		27,586	9
954,407	-76,064	693,237	1,571,580	10
350,548	289,640	220,961	861,149	11
142,639	-971,012	107,370	-721,004	12
		9,220	9,220	13
		633,769	633,769	14
		255	255	15
				16
	163,580		163,580	17
		151	151	18
		3,496	3,496	19
		840	840	20
		530,631	530,631	21
		185	185	22
		755,162	755,162	23
		13,551	13,551	24
		85,322	85,322	25
		46	46	26
				27
	559,884		559,884	28
		63,965	63,965	29
		433	433	30
		58	58	31
		931	931	32
	30,760		30,760	33
		656	656	34
1,600,425	897,657	7,243,989	9,742,070	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	123		123	1
		156,557	156,557	2
		73,342	73,342	3
		12,747	12,747	4
		13,121	13,121	5
		52	52	6
				7
	84,903		84,903	8
		85,354	85,354	9
		1,806	1,806	10
	4,326		4,326	11
		11	11	12
		116	116	13
		862	862	14
	373		373	15
		109	109	16
		258	258	17
	122		122	18
		129,355	129,355	19
		2,040,217	2,040,217	20
		286,646	286,646	21
		7,364	7,364	22
		10,113	10,113	23
		6,101	6,101	24
				25
	781,846		781,846	26
		800	800	27
	381		381	28
		10,819	10,819	29
		53,480	53,480	30
		2,340	2,340	31
		4,816	4,816	32
		2,441	2,441	33
				34
1,600,425	897,657	7,243,989	9,742,070	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	98,372		98,372	1
		4,666	4,666	2
		17,328	17,328	3
		1,062	1,062	4
	7,763		7,763	5
		115	115	6
	34		34	7
		1	1	8
				9
		64,299	64,299	10
		64,299	64,299	11
		70,729	70,729	12
		70,729	70,729	13
	85,627	46,094	131,721	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
1,600,425	897,657	7,243,989	9,742,070	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Schedule Page: 328 Line No.: 1 Column: d

Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 1 Column: m

Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

Schedule Page: 328 Line No.: 2 Column: d

Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 2 Column: m

Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

Schedule Page: 328 Line No.: 3 Column: d

Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 3 Column: m

Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

Schedule Page: 328 Line No.: 4 Column: d

Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 4 Column: m

Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

Schedule Page: 328 Line No.: 5 Column: d

Exchange agreement with PacifiCorp.

Schedule Page: 328 Line No.: 5 Column: m

Pre-888 contract executed between PGE and the PacifiCorp concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the PacifiCorp, Exchange Agreement).

Schedule Page: 328 Line No.: 6 Column: l

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

Schedule Page: 328 Line No.: 6 Column: m

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.

Schedule Page: 328 Line No.: 7 Column: l

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

Schedule Page: 328 Line No.: 7 Column: m

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.

Schedule Page: 328 Line No.: 8 Column: l

Charges or credits resulting from the provision of Energy Imbalance Service in accordance

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with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

Schedule Page: 328 Line No.: 8 Column: m

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.

Schedule Page: 328 Line No.: 10 Column: l

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

Schedule Page: 328 Line No.: 10 Column: m

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.

Schedule Page: 328 Line No.: 11 Column: l

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

Schedule Page: 328 Line No.: 11 Column: m

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.

Schedule Page: 328 Line No.: 12 Column: l

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

Schedule Page: 328 Line No.: 12 Column: m

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.

Schedule Page: 328 Line No.: 13 Column: d

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

Schedule Page: 328 Line No.: 13 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 14 Column: d

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

Schedule Page: 328 Line No.: 14 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 15 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 16 Column: d

Represents non-billed redirected MWHs.

Schedule Page: 328 Line No.: 17 Column: d

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

Schedule Page: 328 Line No.: 18 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 19 Column: m

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Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 20 Column: d

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

Schedule Page: 328 Line No.: 21 Column: d

Contract with Shell Energy North America (US) LP expires 12/31/2021.

Schedule Page: 328 Line No.: 21 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 22 Column: d

Contract with Shell Energy North America (US) LP expires 12/31/2021.

Schedule Page: 328 Line No.: 22 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 23 Column: d

Contract with Shell Energy North America (US) LP expires 12/31/2021.

Schedule Page: 328 Line No.: 23 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 24 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 25 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 26 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 27 Column: d

Represents non-billed redirected MWHs.

Schedule Page: 328 Line No.: 28 Column: d

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

Schedule Page: 328 Line No.: 29 Column: d

Contract with Constellation New Energy expires 01/01/2034.

Schedule Page: 328 Line No.: 29 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 30 Column: d

Contract with Constellation New Energy expires 01/01/2034.

Schedule Page: 328 Line No.: 30 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 31 Column: d

Contract with Constellation New Energy expires 01/01/2034.

Schedule Page: 328 Line No.: 31 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 32 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328 Line No.: 33 Column: d

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

Schedule Page: 328 Line No.: 34 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 2 Column: d

Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

Schedule Page: 328.1 Line No.: 2 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 3 Column: d

Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

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Schedule Page: 328.1 Line No.: 3 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 4 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 5 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 6 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 7 Column: d

Represents non-billed redirected MWHs.

Schedule Page: 328.1 Line No.: 8 Column: d

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

Schedule Page: 328.1 Line No.: 9 Column: d

Contract with PacifiCorp expires 04/01/2022.

Schedule Page: 328.1 Line No.: 9 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 10 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 11 Column: d

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

Schedule Page: 328.1 Line No.: 12 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 13 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 14 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 15 Column: d

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

Schedule Page: 328.1 Line No.: 16 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 17 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 18 Column: d

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

Schedule Page: 328.1 Line No.: 19 Column: d

Contract with PowerEx expires 01/01/2022.

Schedule Page: 328.1 Line No.: 19 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 20 Column: d

Contract with PowerEx expires 01/01/2022.

Schedule Page: 328.1 Line No.: 20 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 21 Column: d

Contract with PowerEx expires 01/01/2022.

Schedule Page: 328.1 Line No.: 21 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 22 Column: m

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Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 23 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 24 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 25 Column: d

Represents non-billed redirected MWHs.

Schedule Page: 328.1 Line No.: 26 Column: d

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

Schedule Page: 328.1 Line No.: 27 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 28 Column: d

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

Schedule Page: 328.1 Line No.: 29 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.1 Line No.: 29 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 30 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.1 Line No.: 30 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 31 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 32 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 33 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.1 Line No.: 34 Column: d

Represents non-billed redirected MWHs.

Schedule Page: 328.2 Line No.: 1 Column: d

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

Schedule Page: 328.2 Line No.: 2 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 3 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 4 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 5 Column: d

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

Schedule Page: 328.2 Line No.: 6 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 7 Column: d

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

Schedule Page: 328.2 Line No.: 9 Column: d

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially

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under Schedule 11.

Schedule Page: 328.2 Line No.: 10 Column: d

Contract with PUD No. 1 of Cowlitz County expires 01/01/2034.

Schedule Page: 328.2 Line No.: 10 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 11 Column: d

Contract with PUD No. 1 of Franklin County expires 01/01/2034.

Schedule Page: 328.2 Line No.: 11 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 12 Column: d

Contract with PUD No. 1 of Klickitat County expires 01/01/2034.

Schedule Page: 328.2 Line No.: 12 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 13 Column: d

Contract with PUD No. 1 of Lewis County expires 01/01/2034.

Schedule Page: 328.2 Line No.: 13 Column: m

Includes Scheduling, system control and dispatch service.

Schedule Page: 328.2 Line No.: 14 Column: d

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.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
 (Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Bonneville Power Admin	LFP			66,511,983			66,511,983
2	Bonneville Power Admin	OS	171,548	171,548			14,862,921	14,862,921
3	Bonneville Power Admin	SFP	5,101	5,101		48,218		48,218
4	Bonneville Power Admin	NF	3,442	3,442		32,639		32,639
5	Bonneville Power Admin	AD					-201,188	-201,188
6	Avista Corp	NF	7,777	7,777		44,873		44,873
7	Calpine Energy Services	LFP	18,700	18,700		51,900		51,900
8	Columbia River PUD	SFP	13	13		19,032		19,032
9	DET - Gamesa	OS					-1,749,543	-1,749,543
10	EDF Renewable N.America	OS					-1,500,000	-1,500,000
11	Eugene Water & Electric	LFP	23	23		110,352		110,352
12	Idaho Power Company	NF	8,400	8,400		41,272		41,272
13	McMinnville Water & Lig	LFP	916	916		9,429		9,429
14	Montana, State of	OS					2,156,041	2,156,041
15	MACQUARIE ENERGY LLC	NF	2	2		9,200		9,200
16	Morgan Stanley	NF	110,400	110,400		165,600		165,600
	TOTAL		608,517	608,517	66,511,983	1,109,363	13,658,822	81,280,168

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	NorthWestern Energy	NF	41,173	41,173		267,511		267,511
2	PacifiCorp	OS					90,591	90,591
3	PacifiCorp	SFP	82,960	82,960		62,721		62,721
4	Puget Sound Energy	NF	156,912	156,912		244,928		244,928
5	Seattle City Light	NF	1,150	1,150		1,688		1,688
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		608,517	608,517	66,511,983	1,109,363	13,658,822	81,280,168

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: b

Represents Bonneville Power Administration PTP contracts that have termination dates that range from 10/1/2020 - 1/1/2030.

Schedule Page: 332 Line No.: 2 Column: g

Represents Bonneville Power Administration Ancillary Transmission Services.

Schedule Page: 332 Line No.: 5 Column: g

Represents Bonneville Power Administration prior period adjustments and monthly billing offsets.

Schedule Page: 332 Line No.: 9 Column: g

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

Schedule Page: 332 Line No.: 10 Column: g

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

Schedule Page: 332 Line No.: 11 Column: b

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

Schedule Page: 332 Line No.: 13 Column: b

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

Schedule Page: 332 Line No.: 14 Column: g

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

Schedule Page: 332.1 Line No.: 2 Column: g

Represents PacifiCorp's Linneman Transmission Services.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,387,303
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,475,704
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	2,283,192
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Involuntary Severance	8,394,117
7	Directors Pension	160,032
8	Directors Fees and Expenses	460,220
9	Directors and Officers Expenses	2,334,299
10	Misc. Admin expenses	251,139
11	Colstrip - PPL Montana	1,974,140
12		
13		
14		
15		
16		
17		
18		
19		
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21		
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41		
42		
43		
44		
45		
46	TOTAL	20,720,146

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
 (Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			64,345,245		64,345,245
2	Steam Production Plant	35,635,281	-4,755,833			30,879,448
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	22,253,338	69			22,253,407
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	77,911,218	783,863			78,695,081
7	Transmission Plant	17,911,508	1			17,911,509
8	Distribution Plant	120,963,563	5,528			120,969,091
9	Regional Transmission and Market Operation					
10	General Plant	40,658,204	99			40,658,303
11	Common Plant-Electric					
12	TOTAL	315,333,112	-3,966,273	64,345,245		375,712,084

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 amortization of hydro licensing costs.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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						
13	rates for all assets						
14	effective 1/1/2018 per						
15	Order 17-365 in						
16	OPUC Docket UM-1809						
17							
18							
19							
20							
21							
22							
23							
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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FERC-NERC Reliability		283,706	283,706	
2	Docket RM06-16				
3					
4	FERC-NERC Reliability		118,110	118,110	
5	Docket RM06-22				
6					
7	FERC matters less than \$25,000		10,565	10,565	
8					
9	OPUC Docket UM 1631		87,917	87,917	
10					
11	OPUC Docket UM 1971		37,519	37,519	
12					
13	OPUC Docket UM 2009		407,969	407,969	
14					
15	OPUC Docket UM 2032		127,442	127,442	
16					
17	OPUC Docket UM 2051		174,115	174,115	
18					
19	OPUC Docket UM 2057		148,416	148,416	
20					
21	OPUC Docket UM 2074		85,667	85,667	
22					
23	OPUC matters less than \$25,000		319,735	319,735	
24					
25	Unassigned Non-Doc Matters		378,842	378,842	
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
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41					
42					
43					
44					
45					
46	TOTAL		2,180,003	2,180,003	

REGULATORY COMMISSION EXPENSES (Continued)

- 3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
- 4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
- 5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
	928	283,706					1
							2
							3
	928	118,110					4
							5
							6
	928	10,565					7
							8
	928	87,917					9
							10
	928	37,519					11
							12
	928	407,969					13
							14
	928	127,442					15
							16
	928	174,115					17
							18
	928	148,416					19
							20
	928	85,667					21
							22
	928	319,735					23
							24
	928	378,842					25
							26
							27
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		2,180,003					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:

- (1) Generation
 - a. hydroelectric
 - i. Recreation fish and wildlife
 - ii Other hydroelectric
- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Unconventional generation
- f. Siting and heat rejection
- (2) Transmission

a. Overhead

b. Underground

- (3) Distribution
 - (4) Regional Transmission and Market Operation
 - (5) Environment (other than equipment)
 - (6) Other (Classify and include items in excess of \$50,000.)
 - (7) Total Cost Incurred
- B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)(c)	Electric R, D & D Performed Internally - Internal combustion or gas turbin
2	A(6)	Electric R, D & D Performed Internally - Other
3	B(1)	Electric R, D & D Performed Externally
4	B(4)	Electric R, D & D Performed Externally
5		
6		
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19		
20	Totals	
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
- (3) Research Support to Nuclear Power Groups
- (4) Research Support to Others (Classify)
- (5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
154,700		930.2	154,700		1
136,641		930.2	136,641		2
	1,578,150	930.2	1,578,150		3
	531,795	930.2	531,795		4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
291,341	2,109,945		2,401,286		20
					21
					22
					23
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	32,842,457		
4	Transmission	6,888,520		
5	Regional Market			
6	Distribution	10,342,161		
7	Customer Accounts	25,168,449		
8	Customer Service and Informational	6,922,223		
9	Sales			
10	Administrative and General	37,259,129		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	119,422,939		
12	Maintenance			
13	Production	12,540,044		
14	Transmission	869,120		
15	Regional Market			
16	Distribution	25,632,916		
17	Administrative and General	1,300,033		
18	TOTAL Maintenance (Total of lines 13 thru 17)	40,342,113		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	45,382,501		
21	Transmission (Enter Total of lines 4 and 14)	7,757,640		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	35,975,077		
24	Customer Accounts (Transcribe from line 7)	25,168,449		
25	Customer Service and Informational (Transcribe from line 8)	6,922,223		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	38,559,162		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	159,765,052	28,729,458	188,494,510
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
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 Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	159,765,052	28,729,458	188,494,510
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	121,503,485	4,760,690	126,264,175
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	121,503,485	4,760,690	126,264,175
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,611,505	118,918	2,730,423
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,611,505	118,918	2,730,423
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,360,421	308,193	1,668,614
79	Co-Owner Shares of Generating Facilities	5,133,579	250,015	5,383,594
80	Other	8,468,060	452,106	8,920,166
81	Payroll Allocated	34,619,380	-34,619,380	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	49,581,440	-33,609,066	15,972,374
96	TOTAL SALARIES AND WAGES	333,461,482		333,461,482

Name of Respondent Document Accession #: 20210420-8046 Portland General Electric Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2020/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Document Accession #: 20210420-8026

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	2,413,966	322,215	1,366,660	6,522,780
3	Net Sales (Account 447)	18,527,663	9,017,384	10,960,439	57,852,640
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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11					
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41					
42					
43					
44					
45					
46	TOTAL	20,941,629	9,339,599	12,327,099	64,375,420

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 397 Line No.: 2 Column: e

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

Schedule Page: 397 Line No.: 3 Column: e

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

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	171,445	MWH	15,262,431	6,251,208	MWH	161,099
2	Reactive Supply and Voltage				4,125,740	MWH	135,446
3	Regulation and Frequency Response				4,124,612	MWH	302,029
4	Energy Imbalance	130,607	MWH	2,408,358	952,519	MWH	1,459,496
5	Operating Reserve - Spinning				3,417	MW	343,152
6	Operating Reserve - Supplement				3,417	MW	343,152
7	Other						
8	Total (Lines 1 thru 7)	302,052		17,670,789	15,460,913		2,744,374

Name of Respondent Portland General Electric Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 4 Column: b

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.

Schedule Page: 398 Line No.: 4 Column: d

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.

Schedule Page: 398 Line No.: 4 Column: e

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.

Schedule Page: 398 Line No.: 4 Column: g

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.

Schedule Page: 398 Line No.: 5 Column: e

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.

Schedule Page: 398 Line No.: 6 Column: e

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.

Document Accession #: 20210420-8026 Submission Date: 04/16/2021

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: PGE

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)
1	January	4,948	27	10	2,520	280	2,661	66	1,502	179
2	February	4,937	3	19	2,888	275	2,661	78	1,502	132
3	March	4,500	2	21	2,543	270	2,661	66	1,708	
4	Total for Quarter 1				7,951	825	7,983	210	4,712	311
5	April	4,548	3	11	2,480	258	2,661	61	2,058	227
6	May	4,637	28	19	2,824	298	2,661	61	1,908	104
7	June	4,410	23	22	2,767	297	2,661	56	1,508	54
8	Total for Quarter 2				8,071	853	7,983	178	5,474	385
9	July	5,200	20	20	3,264	311	2,661	86	1,508	106
10	August	4,976	17	20	3,264	321	2,661	77	1,508	569
11	September	5,013	7	18	2,856	287	2,661	77	1,508	105
12	Total for Quarter 3				9,384	919	7,983	240	4,524	780
13	October	4,032	27	9	2,750	288	2,661	55	1,508	294
14	November	4,601	30	20	2,733	271	2,661	65	1,908	4
15	December	4,947	21	20	2,604	251	2,661	64	1,808	295
16	Total for Quarter 4				8,087	810	7,983	184	5,224	593
17	Total Year to Date/Year				33,493	3,407	31,932	812	19,934	2,069

Name of Respondent

Portland General Electric Company

Document Accession #: 20210420-8026

This Report Is:

(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)

Submission Date: 04/16/2021

Year/Period of Report

End of 2020/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
- (2) Report on Column (b) by month the transmission system's peak load.
- (3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
- (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
- (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,423,803
3	Steam	3,232,095	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,442,580
5	Hydro-Conventional	1,204,249	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	25,725
7	Other	10,140,288	27	Total Energy Losses	1,045,901
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	24,938,009
9	Net Generation (Enter Total of lines 3 through 8)	14,576,632			
10	Purchases	10,358,031			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	6,818,609			
17	Delivered	6,815,263			
18	Net Transmission for Other (Line 16 minus line 17)	3,346			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	24,938,009			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	2,400,930	700,599	3,330	14	19
30	February	2,167,445	595,848	3,259	4	8
31	March	2,230,913	643,460	3,117	9	8
32	April	1,870,056	518,443	2,804	1	11
33	May	1,825,915	472,278	3,114	28	18
34	June	1,721,238	372,523	3,408	23	18
35	July	2,174,905	617,050	3,771	27	18
36	August	2,222,254	624,827	3,696	17	18
37	September	2,112,194	659,874	3,661	3	18
38	October	1,983,955	503,546	3,024	27	9
39	November	2,053,865	430,077	3,157	9	18
40	December	2,170,993	414,146	3,367	29	18
41	TOTAL	24,934,663	6,552,671			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 9 Column: b

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, Coyote Springs, and Carty generation plants (as shown on page 403), and generation from PGE's solar generation facilities (as shown on page 410), other generation includes 2,111,182 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 2,118,799 megawatt hours.

The Biglow 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 12/31/2020: \$941,644,956
 Total installed capacity: 450 megawatts
 Operations and maintenance expense for 2020: \$14,894,590

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

In-service production cost at 12/31/2020: \$487,294,286
 Total installed capacity: 267 megawatts
 Operations and maintenance expense for 2020: \$8,058,003

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

In-service production cost at 12/31/2020: \$151,796,820
 Total installed capacity: 100 megawatts
 Operations and maintenance expense for 2020: \$172,988

Schedule Page: 401 Line No.: 27 Column: b

PGE has ownership in a 5 megawatt storage battery (Salem Smart Power Center) with a FERC 101 Plant-in-service balance of \$384,933 as of 12/31/2020, recorded to FERC 363 - Storage Battery Equipment, Distribution. This battery is located in the Salem, Oregon area and is connected to PGE's Oxford substation. PGE recorded expenses for 2020 to FERC 592.2 - Maintenance of Energy Storage Equipment \$34,703. Line loss includes approximately 0.84 MWh of energy stored in the battery as of 12/31/2020.

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	Plant Name: Boardman		Plant Name: Boardman (PGE Share)			
		(b)		(c)			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam		Steam			
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional			
3	Year Originally Constructed	1980		1980			
4	Year Last Unit was Installed	1980		1980			
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	642.20		578.00			
6	Net Peak Demand on Plant - MW (60 minutes)	575		0			
7	Plant Hours Connected to Load	3560		0			
8	Net Continuous Plant Capability (Megawatts)	0		0			
9	When Not Limited by Condenser Water	575		0			
10	When Limited by Condenser Water	575		0			
11	Average Number of Employees	62		0			
12	Net Generation, Exclusive of Plant Use - KWh	1616407000		1477803000			
13	Cost of Plant: Land and Land Rights	0		0			
14	Structures and Improvements	0		0			
15	Equipment Costs	0		0			
16	Asset Retirement Costs	0		0			
17	Total Cost	0		0			
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000		0.0000			
19	Production Expenses: Oper, Supv, & Engr	2676286		2276048			
20	Fuel	43129093		39463121			
21	Coolants and Water (Nuclear Plants Only)	0		0			
22	Steam Expenses	14446373		13491345			
23	Steam From Other Sources	0		0			
24	Steam Transferred (Cr)	0		0			
25	Electric Expenses	0		0			
26	Misc Steam (or Nuclear) Power Expenses	4342562		3662198			
27	Rents	0		0			
28	Allowances	0		0			
29	Maintenance Supervision and Engineering	184330		233500			
30	Maintenance of Structures	178690		147643			
31	Maintenance of Boiler (or reactor) Plant	337907		276981			
32	Maintenance of Electric Plant	3969200		3357353			
33	Maintenance of Misc Steam (or Nuclear) Plant	291417		263323			
34	Total Production Expenses	69555858		63171512			
35	Expenses per Net KWh	0.0430		0.0427			
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	983210	3927	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8611	138800	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	42.216	87.606	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	43.516	87.606	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.527	15.040	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10475.600	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

Line No.	Item (a)	Plant Name: (b)	Plant Name: Colstrip (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	311.20				
6	Net Peak Demand on Plant - MW (60 minutes)	0	0				
7	Plant Hours Connected to Load	0	0				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	0	0				
10	When Limited by Condenser Water	0	0				
11	Average Number of Employees	0	0				
12	Net Generation, Exclusive of Plant Use - KWh	0	1754292000				
13	Cost of Plant: Land and Land Rights	0	3328862				
14	Structures and Improvements	0	117298194				
15	Equipment Costs	0	374230633				
16	Asset Retirement Costs	0	34911263				
17	Total Cost	0	529768952				
18	Cost per KW of Installed Capacity (line 17/5) Including	0	1702.3424				
19	Production Expenses: Oper, Supv, & Engr	0	74997				
20	Fuel	0	31213031				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	0	2342810				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	0	0				
26	Misc Steam (or Nuclear) Power Expenses	0	4241461				
27	Rents	0	0				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	0	731398				
30	Maintenance of Structures	0	846009				
31	Maintenance of Boiler (or reactor) Plant	0	7904507				
32	Maintenance of Electric Plant	0	1739158				
33	Maintenance of Misc Steam (or Nuclear) Plant	0	573286				
34	Total Production Expenses	0	49666657				
35	Expenses per Net KWh	0.0000	0.0283				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0			0
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 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.

Plant Name: <i>Beaver</i> (d)			Plant Name: <i>Port Westward 1</i> (e)			Plant Name: <i>Coyote Springs</i> (f)			Line No.
Gas & Steam Turbine			Gas & Steam Turbine			Gas & Steam Turbine			1
Outdoor			Outdoor			Outdoor			2
1974			2007			1995			3
2001			2007			1995			4
573.20			483.30			296.00			5
398			426			276			6
2111			6979			6656			7
0			0			0			8
533			421			270			9
0			0			0			10
45			27			32			11
371881000			2640315000			1596387000			12
24473			24473			0			13
38076651			42833536			11634202			14
222580002			243525017			190146850			15
2941318			231072			113193			16
263622444			286614098			201894245			17
459.9135			593.0356			682.0752			18
512145			845764			126386			19
9500116			53506856			26598222			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1716231			2619308			1201579			25
2385403			1577882			751021			26
217035			28586			0			27
0			0			0			28
1358329			248644			-27773			29
127897			35740			53307			30
0			0			0			31
2732268			5165519			5155522			32
349261			71785			37169			33
18898685			64100084			33895433			34
0.0508			0.0243			0.0212			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
3807558	353	0	18135983	0	0	11347215	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
2.480	0.000	0.000	2.537	0.000	0.000	1.831	0.000	0.000	40
2.486	97.371	0.000	2.950	0.000	0.000	2.344	0.000	0.000	41
2.439	16.748	0.000	2.894	0.000	0.000	2.299	0.000	0.000	42
0.026	0.000	0.000	0.020	0.000	0.000	0.017	0.000	0.000	43
10442.476	0.000	0.000	7001.900	0.000	0.000	7245.700	0.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 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.

Plant Name: <i>Port Westward 2</i> (d)	Plant Name: <i>Carty</i> (e)	Plant Name: (f)	Line No.
Reciprocating Engine	Gas & Steam Turbine		1
Outdoor	Outdoor		2
2014	2016		3
2014	2016		4
225.10	503.10	0.00	5
224	466	0	6
3999	7208	0	7
0	0	0	8
225	0	0	9
0	0	0	10
0	27	0	11
448545000	2967457000	0	12
0	0	0	13
42352598	86306276	0	14
248382121	429265205	0	15
647461	10434861	0	16
291382180	526006342	0	17
1294.4566	1045.5304	0	18
18168	296973	0	19
10698762	55585824	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
343287	2620924	0	25
964531	2353703	0	26
33347	0	0	27
0	0	0	28
9714	93877	0	29
6403	-97	0	30
0	0	0	31
1508768	6119026	0	32
104849	271057	0	33
13687829	67341287	0	34
0.0305	0.0227	0.0000	35
Gas	Oil		36
Mcf's	Barrels		37
3792133	0	0	38
1019000	138690	0	39
2.976	0.000	0.000	40
2.821	0.000	0.000	41
2.767	0.000	0.000	42
0.024	0.000	0.000	43
8618.000	0.000	0.000	44
20011045	0	0	
1019000	138690	0	
1.836	0.000	0.000	
2.778	0.000	0.000	
2.725	0.000	0.000	
0.019	0.000	0.000	
6874.100	0.000	0.000	

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b

Respondent is the principal owner (90% interest) and operator of the Boardman Plant. The other owner is Idaho Power Company (10%). Reported here are 100% costs and plant statistics, including shared and non-shared costs. The Boardman plant was retired in 4Q 2020.

Schedule Page: 402 Line No.: -1 Column: c

Respondent is the principal owner and operator of the Boardman Plant. Installed capacity in line 5c represents 90% share. Reported here are the respondent's share of expenses incurred during the year and investment as of December 31, 2020, as appropriate. Details are reported in Page 402 col (b). The Boardman plant was retired in 4Q 2020.

Schedule Page: 403 Line No.: 9 Column: d

Based on January average temperature.

Schedule Page: 403 Line No.: 9 Column: e

Based on January average temperature.

Schedule Page: 403 Line No.: 9 Column: f

Based on January average temperature.

Schedule Page: 402.1 Line No.: -1 Column: c

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

Schedule Page: 402 Line No.: 44 Column: b2

The Boardman Coal Plant does not use oil for generation. Oil is used during start up or set up conditions and other temporary operating conditions.

Schedule Page: 402 Line No.: 44 Column: d1

The Beaver 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.

Schedule Page: 402 Line No.: 44 Column: e1

The Port Westward 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.

Schedule Page: 402 Line No.: 44 Column: f1

The Coyote Springs 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.

Schedule Page: 402.1 Line No.: 44 Column: d1

The Port Westward 2 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.

Schedule Page: 402.1 Line No.: 44 Column: e1

The Carty 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.

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 2195 Plant Name: Faraday (b)	FERC Licensed Project No. 2195 Plant Name: North Fork (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of River;Storage	Run-of River
2	Plant Construction type (Conventional or Outdoor)	Conventional;Outdoor	Outdoor
3	Year Originally Constructed	1907	1958
4	Year Last Unit was Installed	1958	1958
5	Total installed cap (Gen name plate Rating in MW)	36.81	50.25
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	57
7	Plant Hours Connect to Load	0	8,433
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	46	58
10	(b) Under the Most Adverse Oper Conditions	5	7
11	Average Number of Employees	53	0
12	Net Generation, Exclusive of Plant Use - Kwh	-7,000	163,729,000
13	Cost of Plant		
14	Land and Land Rights	33,434	377,100
15	Structures and Improvements	19,021,225	9,196,031
16	Reservoirs, Dams, and Waterways	33,030,468	85,742,690
17	Equipment Costs	11,734,275	13,280,242
18	Roads, Railroads, and Bridges	2,441,325	2,767,794
19	Asset Retirement Costs	90	6
20	TOTAL cost (Total of 14 thru 19)	66,260,817	111,363,863
21	Cost per KW of Installed Capacity (line 20 / 5)	1,800.0765	2,216.1963
22	Production Expenses		
23	Operation Supervision and Engineering	296,185	19,912
24	Water for Power	68,848	54,108
25	Hydraulic Expenses	1,353,489	660,316
26	Electric Expenses	649,072	245,573
27	Misc Hydraulic Power Generation Expenses	777,849	490,526
28	Rents	130,044	90,043
29	Maintenance Supervision and Engineering	516,954	1,072
30	Maintenance of Structures	4,894	0
31	Maintenance of Reservoirs, Dams, and Waterways	7,030	55,299
32	Maintenance of Electric Plant	108,127	17,103
33	Maintenance of Misc Hydraulic Plant	726,817	222,363
34	Total Production Expenses (total 23 thru 33)	4,639,309	1,856,315
35	Expenses per net KWh	0.0000	0.0113

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 2030 Plant Name: Pelton (b)	FERC Licensed Project No. 2030 Plant Name: Pelton (PGE%) (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1957	1957
4	Year Last Unit was Installed	1958	1958
5	Total installed cap (Gen name plate Rating in MW)	110.20	73.47
6	Net Peak Demand on Plant-Megawatts (60 minutes)	97	0
7	Plant Hours Connect to Load	8,765	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	0
10	(b) Under the Most Adverse Oper Conditions	60	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	343,185,000	228,790,000
13	Cost of Plant		
14	Land and Land Rights	3,681,439	2,454,415
15	Structures and Improvements	9,522,633	6,359,006
16	Reservoirs, Dams, and Waterways	15,710,616	10,705,389
17	Equipment Costs	23,497,467	15,917,265
18	Roads, Railroads, and Bridges	6,076,338	4,310,174
19	Asset Retirement Costs	52	52
20	TOTAL cost (Total of 14 thru 19)	58,488,545	39,746,301
21	Cost per KW of Installed Capacity (line 20 / 5)	530.7490	540.9868
22	Production Expenses		
23	Operation Supervision and Engineering	305,245	188,911
24	Water for Power	173,182	97,537
25	Hydraulic Expenses	2,479,213	1,711,672
26	Electric Expenses	286,068	187,021
27	Misc Hydraulic Power Generation Expenses	803,937	535,346
28	Rents	10,679	4,626
29	Maintenance Supervision and Engineering	368,568	245,715
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	51,446	51,446
32	Maintenance of Electric Plant	249,728	120,052
33	Maintenance of Misc Hydraulic Plant	229,446	140,132
34	Total Production Expenses (total 23 thru 33)	4,957,512	3,282,458
35	Expenses per net KWh	0.0144	0.0143

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 2195 Plant Name: River Mill (d)	FERC Licensed Project No. 2195 Plant Name: Oak Grove (e)	FERC Licensed Project No. 2233 Plant Name: Sullivan (f)	Line No.
Run-of River	Run-of River	Run-of River	1
Conventional	Conventional	Conventional	2
1911	1924	1895	3
1952	1931	1953	4
20.60	51.00	15.40	5
26	39	18	6
8,236	6,026	8,234	7
			8
25	44	18	9
4	19	7	10
0	4	1	11
84,451,000	105,388,000	106,730,000	12
			13
86,408	9,457	572,077	14
7,518,906	16,202,242	19,611,993	15
58,745,880	27,259,810	31,499,172	16
11,739,936	23,960,463	14,507,819	17
421,796	3,961,942	0	18
64	2,122	2,630	19
78,512,990	71,396,036	66,193,691	20
3,811.3102	1,399.9223	4,298.2916	21
			22
14,256	21,394	2,347	23
44,773	67,806	37,074	24
313,233	1,202,553	205,588	25
32,375	100,045	234,482	26
293,013	401,411	221,475	27
0	562,343	0	28
1,098	167,431	298	29
0	0	0	30
1,989	4,656	74,206	31
310,619	222,331	205,836	32
65,840	126,378	41,629	33
1,077,196	2,876,348	1,022,935	34
0.0128	0.0273	0.0096	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 2030 Plant Name: Round Butte (d)	FERC Licensed Project No. 2030 Plant Name: Round Butte (PGE%) (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage	Storage		1
Conventional	Conventional		2
1964	1964		3
1964	1964		4
372.50	248.33	0.00	5
232	0	0	6
8,768	0	0	7
			8
345	0	0	9
192	0	0	10
43	0	0	11
772,752,000	515,168,000	0	12
			13
3,726,481	2,521,012	0	14
18,803,549	12,575,060	0	15
170,622,348	111,482,004	0	16
52,832,304	40,364,041	0	17
2,564,265	1,794,840	0	18
165	165	0	19
248,549,112	168,737,122	0	20
667.2459	679.4875	0.0000	21
			22
386,191	244,005	0	23
331,167	238,712	0	24
2,640,385	1,702,280	0	25
374,308	253,251	0	26
983,796	655,518	0	27
29,676	22,278	0	28
212,050	61,896	0	29
0	0	0	30
167,460	167,460	0	31
530,310	371,817	0	32
366,037	256,876	0	33
6,021,380	3,974,093	0	34
0.0078	0.0077	0.0000	35

Name of Respondent Portland General Electric Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 406 Line No.: 6 Column: b

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.

Schedule Page: 406 Line No.: 7 Column: b

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.

Schedule Page: 406 Line No.: 12 Column: b

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.

Schedule Page: 406.1 Line No.: -1 Column: b

Respondent is the principal owner (66.67% interest) and operator of the Pelton 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.

Schedule Page: 406.1 Line No.: -1 Column: c

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on 406.1, column (b). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: -1 Column: d

Respondent is the principal owner (66.67% interest) and operator of the Round Butte 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.

Schedule Page: 406.1 Line No.: -1 Column: e

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on 406.1, column (d). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: 11 Column: b

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.

Schedule Page: 406.1 Line No.: 11 Column: d

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.

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Maclaren	1999	0.50	0.4	9	133,799
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	54	186,058
3	US Bank Corp Columbia Center	2001	6.89	6.2	1,018	488,057
4	Portland State University	2004	2.80	2.8	32	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	58	191,439
6	Stimson Lumber	2005	0.57	0.5	13	159,546
7	Flexential (Formerly ViaWest)	2005	9.00	8.0	1,127	629,125
8	Skyline	2005	2.00	1.8	44	201,526
9	Tri-Quint	2005	0.60	0.5	2	109,968
10	NCCWC- Filter Plant	2005	2.00	1.8	31	122,958
11	PCC Structurals	2005	1.00	0.9	9	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	487	265,383
13	Salem Hospital	2006	8.00	7.2	498	269,108
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	11	88,272
15	Providence Newberg Hospital	2006	1.50	1.4	108	156,833
16	vXchnge (Formerly Sungard DSG)	2006	2.00	1.8	26	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.1	551	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	32	154,458
19	Xerox Corp	2007	4.00	3.6	108	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	19	78,159
21	Oregon Dept of Admin Serv - Data Center	2010	2.60	2.3	240	277,254
22	Panasonic (Formerly Sanyo)	2010	1.00	0.9	13	43,144
23	Sysco Foods	2010	2.00	1.8	27	184,779
24	Clackamas Intertie 2	2012	0.60	0.5	8	155,832
25	Dawson Creek	2012	0.80	0.7	12	95,706
26	Kaiser Westside Hospital	2012	4.00	3.6	210	408,830
27	North Plains Pump Station	2012	0.80	0.7	12	53,132
28	Oak Lodge Sanitary District	2012	2.00	1.8	29	229,144
29	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	21	284,255
30	Oregon State Hospital	2012	4.00	3.6	189	172,879
31	Portland Service Center	2012	0.50	0.5	10	322,856
32	Sandy High School	2012	1.25	1.1	23	179,894
33	TATA Communications - Hillsboro	2012	3.56	3.2	157	328,979
34	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	36	161,695
35	TATA Communications - Portland	2013	6.60	5.4	225	612,983
36	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	13	105,854
37	East County Courts	2013	1.50	1.4	163	316,848
38	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	13	162,234
39	Food Services of America	2013	2.00	1.8	26	229,875
40	Avery DSG	2014	0.80	0.7	13	263,782
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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Carver (Readiness Center) DSG	2014	2.00	1.8	74	818,635
2	Juvenile Justice Center	2014	0.75	0.7	20	171,380
3	Clackamas River Water DSG	2014	2.00	1.8	31	383,436
4	Joint Water Commission	2015	5.00	4.5	146	190,302
5	McLane Foodservice	2016	1.50	1.4	23	181,242
6	Flexential Brookwood (Formerly ViaWest Brookwoo)	2016	16.25	11.4	3,722	278,175
7	World Trade Center	2017	3.20	2.9	256	1,021,168
8	Washington County Jail	2017	1.50	1.4	22	325,428
9	OHSU - Vaccine Gene Therapy Institute	2017	1.50	1.4	19	364,108
10	OHSU - Center for Health & Healing	2018	3.00	2.7	155	347,135
11	OHSU - Knight Cancer Research Building	2018	2.00	1.8	13	234,533
12	Solar	2014	6.00	6.0	4,524	725,400
13	Total					14,306,048
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
267,598		3,253	7,609	diesel-low s	1,687	1
116,286			60,885	diesel-low s	1,127	2
70,856			107,245	diesel-low s	1,127	3
93,476			58,183	diesel-low s	1,127	4
119,649		8,068	38,648	diesel-low s	1,478	5
282,382		955	16,493	diesel-low s	1,037	6
69,903		33,173	85,592	diesel-low s	1,245	7
100,763		5,013	18,257	diesel-low s	1,120	8
183,280			12,824	diesel-low s	1,127	9
61,479		3,566	41,595	diesel-low s	1,191	10
113,874		735	13,361	diesel-low s	1,026	11
44,231		15,217	29,356	diesel-low s	935	12
33,639			46,769	diesel-low s	1,127	13
70,618		2,584	10,685	diesel-low s	1,468	14
104,555		3,021	26,502	diesel-low s	978	15
165,923		4,539	12,789	diesel-low s	1,193	16
78,389		35,878	36,873	diesel-low s	1,656	17
77,229		4,237	24,799	diesel-low s	898	18
95,065		9,675	18,481	diesel-low s	1,240	19
78,159		1,627	20,357	diesel-low s	993	20
106,636		2,240	61,697	diesel-low s	687	21
43,144		1,037	10,664	diesel-low s	1,040	22
92,390		2,287	18,956	diesel-low s	1,079	23
259,720		1,138	19,916	diesel-low s	1,173	24
119,633			19,419	diesel-low s	1,127	25
102,208		10,841	33,041	diesel-low s	860	26
66,415			10,511	diesel-low s	1,127	27
114,572		2,261	14,179	diesel-low s	910	28
189,503		2,099	26,432	diesel-low s	1,071	29
43,220			31,164	diesel-low s	1,127	30
645,712			28,594	diesel-low s	1,127	31
143,915		2,409	13,907	diesel-low s	1,117	32
92,540		13,619	44,288	diesel-low s	1,214	33
64,678		7,843	51,448	diesel-low s	1,013	34
92,876		10,431	80,908	diesel-low s	927	35
132,318		2,064	23,547	diesel-low s	1,550	36
211,232			72,754	diesel-low s	1,127	37
162,234		1,052	12,389	diesel-low s	979	38
114,938		3,577	8,142	diesel-low s	937	39
329,728			6,166	diesel-low s	1,127	40
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
409,318		3,495	17,160	diesel-low s	1,364	1
228,507			6,339	diesel-low s	1,127	2
191,718		4,205	16,015	diesel-low s	1,035	3
38,060		15,200	18,304	diesel-low s	853	4
120,828		2,455	12,237	diesel-low s	1,048	5
17,118		62,843	137,386	diesel-low s	1,082	6
319,115		5,817	29,987	diesel-low s	1,149	7
216,952			8,017	diesel-low s	1,127	8
242,739		1,670	11,590	diesel-low s	1,222	9
115,712		4,761	20,556	diesel-low s	1,072	10
117,267		1,552	12,707	diesel-low s	1,003	11
120,900	542,031		104,742	solar		12
	542,031	296,437	1,670,465			13
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	500KV LINES							
2	BOARDMAN	GRASSLAND	500.00	500.00	ST. TOWER	0.94		1
3	CARTY	GRASSLAND	500.00	500.00	ST. TOWER	0.75		
4	GRASSLAND	BPA SLATT	500.00	500.00	ST. TOWER	16.82		
5	COLSTRIP PROJECT:							
6	COLSTRIP SWITCHYARD	BROADVIEW 'A'	500.00	500.00	ST. TOWER		112.30	1
7	COLSTRIP SWITCHYARD	BROADVIEW 'B'	500.00	500.00	ST. TOWER		115.80	1
8	BROADVIEW SWITCHYARD	TOWNSEND 'A'	500.00	500.00	ST. TOWER		133.40	1
9	BROADVIEW SWITCHYARD	TOWNSEND 'B'	500.00	500.00	ST. TOWER		133.40	
10	COLSTRIP PROJECT	PROJECT LINES						
11	GRIZZLY	ROUND BUTTE	500.00	500.00	ST. TOWER	15.60		1
12	GRIZZLY	MALIN BPA #2	500.00	500.00	ST. TOWER	178.50		1
13	MISCELLANEOUS	MISCELLANEOUS	500.00					
14	JOHN DAY	GRIZZLY '1'	500.00	500.00				1
15	JOHN DAY	GRIZZLY '2'	500.00	500.00				1
16	COYOTE SPRINGS	BPA SLATT	500.00	500.00				2
17	500 KV LINES TOT							
18	TOTAL 500KV LINES					212.61	494.90	10
19								
20	230 KV LINES							
21	BEAVER	PORT WESTWARD	230.00	230.00	H-WOOD	0.41		1
22	BIGLOW CANYON WF	JOHN DAY #1 BPA	230.00	230.00				1
23	CENTRAL FERRY BPA	MULLAN (TUCANNON WF)	230.00	230.00	H-WOOD	20.70		1
24	DALREED PACW	BOARDMAN	230.00	230.00	H-WOOD	16.76		1
25	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
26	PORT WESTWARD	TROJAN #1	230.00	230.00	H-WOOD	8.46		1
27			230.00	230.00	ST. MONOP	10.32		2
28	PORT WESTWARD	TROJAN #2	230.00	230.00	H-WOOD	8.46		1
29			230.00	230.00	ST. MONOP		10.32	2
30	ROUND BUTTE	GENERATOR #1	230.00	230.00	ST. TOWER	0.54		1
31	ROUND BUTTE	GENERATOR #2	230.00	230.00	ST. TOWER	0.54		1
32	ROUND BUTTE	GENERATOR #3	230.00	230.00	ST. TOWER	0.54		1
33	TOTAL PROJECT 230KV					74.60	10.32	14
34								
35	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.52		1
36					TOTAL	1,451.00	559.01	81

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	54.87		1
2			230.00	230.00	ST. TOWER	43.83		1
3	BETHEL	SANTIAM BPA	230.00	230.00	H-WOOD	3.64		1
4	BIG EDDY BPA	McLOUGHLIN	230.00	230.00	H-WOOD	0.91		1
5	BLUE LAKE	GRESHAM	230.00	230.00	ST. TOWER	1.05		1
6			230.00	230.00	ST. TOWER	4.87		2
7	BLUE LAKE	TROUTDALE BPA #1	230.00	230.00	ST. MONOP	0.08		1
8			230.00	230.00	ST. MONOP	0.85		2
9			230.00	230.00	ST. TOWER	0.52		2
10	BLUE LAKE	TROUTDALE BPA #2	230.00	230.00	ST. MONOP	0.12		1
11			230.00	230.00	ST. MONOP		0.90	2
12			230.00	230.00	ST. TOWER		0.52	2
13	CARTLON BPA	SHERWOOD	230.00	230.00	ST. TOWER	8.98	8.98	2
14	CARVER	GRESHAM #1	230.00	230.00	H-WOOD	7.39		1
15	CARVER	McLOUGHLIN #1	230.00	230.00	H-WOOD	4.04		1
16			230.00	230.00	ST. MONOP	0.88		1
17	CARVER	McLOUGHLIN #2	230.00	230.00	ST. MONOP	4.88		1
18	GRESHAM	TROUTDALE PACW #1	230.00	230.00	H-WOOD	0.43	0.43	1
19	GRESHAM	TROUTDALE PACW #2	230.00	230.00	H-WOOD	0.26		1
20	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	0.79		1
21			230.00	230.00	ST. MONOP	0.68		2
22	HORIZON	ST. MARYS - TROJAN	230.00	230.00	ST. TOWER	41.24		1
23			230.00	230.00	ST. MONOP	3.96		1
24	KEELER BPA	RIVERGATE	230.00	230.00	ST. TOWER	0.10		2
25	KEELER BPA	ST. MARYS	230.00	230.00	H-WOOD	2.87		1
26			230.00	230.00	ST. TOWER	3.80		2
27	McLOUGHLIN	PEARL BPA - SHERWOOD	230.00	230.00	ST. TOWER	4.57		2
28			230.00	230.00	ST. TOWER	11.67		2
29			230.00	230.00	ST. MONOP	0.14		2
30	MURRAYHILL	SHERWOOD #1	230.00	230.00	ST. TOWER		5.58	2
31	MURRAYHILL	SHERWOOD #2	230.00	230.00	ST. TOWER	5.58		2
32	MURRAYHILL	ST. MARYS	230.00	230.00	ST. TOWER	3.07		1
33			230.00	230.00	ST. TOWER	2.15		2
34	PEARL BPA	SHERWOOD	230.00	230.00	ST. MONOP	0.16		1
35			230.00	230.00	ST. TOWER		4.19	1
36					TOTAL	1,451.00	559.01	81

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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1			230.00	230.00	H-WOOD		0.59	1
2	REDMOND BPA	ROUND BUTTE	230.00	230.00	H-WOOD	23.58		1
3	RIVERGATE	ROSS BPA	230.00	230.00	ST. TOWER	0.09		2
4	RIVERGATE	TROJAN	230.00	230.00	ST. TOWER	2.48	32.60	2
5	NON-PROJECT 230KV TOT							
6	230KV EXPENSES TOT							
7	TOTAL 230KV LINES					280.05	53.79	57
8								
9	ALL 115KV LINES					430.06		
10	ALL 57KV LINES					11.81		
11	TOT 115KV AND 57 KV					441.87		
12								
13								
14								
15								
16								
17								
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19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,451.00	559.01	81

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-1780 ACSR		4,620,708	4,620,708					2
2-1780 ACSR		10,214,468	10,214,468					3
2-1780 ACSR								4
								5
								6
								7
								8
								9
	1,194,326	43,101,062	44,295,388					10
2-1780 ACSR	50,953	8,520,018	8,570,971					11
2-1780 ACSR	275,427	15,581,384	15,856,811					12
	5,904		5,904					13
		148,889	148,889					14
		148,889	148,889					15
		3,624,934	3,624,934					16
				1,198,557	482,664	521,117	2,202,338	17
	1,526,610	85,960,352	87,486,962	1,198,557	482,664	521,117	2,202,338	18
								19
								20
2156 ACSS								21
		3,040,852	3,040,852					22
954 ACSR		1,956,263	1,956,263					23
795 AAC								24
795 ACSR	7,579	398,550	406,129					25
2156 ACSS								26
2156 ACSS								27
2156 ACSS								28
2156 ACSS								29
795 ACSR								30
795 ACSR								31
795 ACSR								32
	7,579	5,395,665	5,403,244					33
								34
1272 AAC								35
	10,286,131	354,132,656	364,418,787	3,825,449	1,674,830	1,326,887	6,827,166	36

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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	293,351	6,431,090	6,724,441					1
1272 ACSR								2
795 ACSR								3
1780 ACSR								4
1272 ACSS								5
1272 ACSS								6
1272 ACSS								7
1272 ACSS								8
1272 ACSS								9
1272 ACSS								10
1272 ACSS								11
1272 ACSS								12
1272 AAC								13
1272 AAC								14
1272 AAC								15
1272 AAC								16
1272 ACSS								17
954 ACSR								18
1272 AAC								19
1272 ACSS								20
1272 ACSS								21
1590 AAC								22
1590 AAC								23
1272 AAC								24
1590 ACSR TWD								25
1590 ACSR TWD								26
2-1272 AAC								27
1272 AAC								28
2-1780 ACSR								29
1272 AAC								30
1272 AAC								31
1272 AAC								32
1272 AAC								33
2-2388 AAC TW								34
2-2388 AAC TW								35
	10,286,131	354,132,656	364,418,787	3,825,449	1,674,830	1,326,887	6,827,166	36

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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-2388 AAC TW								1
795 ACSR								2
795 ACSR								3
1272 AAC								4
	8,307,341	108,562,847	116,870,188					5
				444,386	151,388	802,404	1,398,178	6
	8,600,692	114,993,937	123,594,629	444,386	151,388	802,404	1,398,178	7
								8
								9
								10
	151,250	147,782,702	147,933,952	2,182,506	1,040,778	3,366	3,226,650	11
								12
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								28
								29
								30
								31
								32
								33
								34
								35
	10,286,131	354,132,656	364,418,787	3,825,449	1,674,830	1,326,887	6,827,166	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 2 Column: a

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

Schedule Page: 422 Line No.: 5 Column: a

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

Schedule Page: 422 Line No.: 14 Column: a

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

Schedule Page: 422 Line No.: 15 Column: a

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

Schedule Page: 422 Line No.: 16 Column: a

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

Schedule Page: 422 Line No.: 22 Column: a

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

Schedule Page: 422 Line No.: 24 Column: b

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

Schedule Page: 422 Line No.: 25 Column: a

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

Schedule Page: 422.1 Line No.: 4 Column: a

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

Schedule Page: 422.1 Line No.: 13 Column: a

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

Schedule Page: 422.1 Line No.: 18 Column: a

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

Schedule Page: 422.1 Line No.: 24 Column: a

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

Schedule Page: 422.1 Line No.: 34 Column: a

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

Schedule Page: 422.2 Line No.: 3 Column: a

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

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	GRESHAM	TROUTDALE PACW #2	0.26	WOOD H FRAME	20.00	1	1
2	BLUE LAKE	MCGILL	4.03	WOOD POLE	25.00	1	1
3	BLUE LAKE	TABOR	13.34	WOOD POLE	20.00	1	1
4	BUTLER	ORENCO	1.26	STEEL POLE	20.00	1	1
5	BUTLER	ST. MARYS	4.68	WOOD POLE	20.00	1	1
6	BUTLER	SUNSET #1	1.44	STEEL POLE	16.00	1	1
7	BUTLER	SUNSET #2	1.49	STEEL POLE	16.00	1	1
8	ORENCO	ROSEWAY	3.00	WOOD POLE	20.00	1	1
9	REEDVILLE	ROSEWAY	1.89	STEEL POLE	15.00	1	1
10	ROCK CREEK	SUNSET	5.26	WOOD POLE	20.00	1	1
11	ROCK CREEK	WEST UNION	2.20	WOOD POLE	20.00	1	1
12							
13							
14							
15							
16							
17							
18							
19							
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41							
42							
43							
44	TOTAL		38.85		212.00	11	11

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1272 AAC			230		121,614			121,614	1
795 ACSS			115		5,749,462	5,749,642		11,499,104	2
795 AAC			115		7,912,764	2,496,995		10,409,759	3
1272 ACSS			115		407,220	407,220		814,440	4
795 AAC			115		407,220	407,220		814,440	5
1272 ACSS			115		407,220	407,220		814,440	6
795 AAC			115		407,220	407,220		814,440	7
795 AAC			115						8
795 AAC			115						9
795 AAC			115		1,790,848	1,790,848		3,581,696	10
795 AAC			115		1,970,779	1,970,779		3,941,558	11
									12
									13
									14
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					19,174,347	13,637,144		32,811,491	44

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	9 Substation < 10 MVA capacity at various locat, OR	Distrib./unattended			
2	Abernethy, Oregon City, OR	Distrib./unattended	115.00	13.00	
3	Amity, near Amity, OR	Distrib./unattended	57.00	13.00	
4	Arlata, Portland, OR	Distrib./unattended	57.00	13.00	
5	Banks, Banks, Or	Distrib./unattended	57.00	13.00	
6	Barnes, Salem, OR	Distrib./unattended	115.00	13.00	
7	Boring, near Boring, OR	Distrib./unattended	57.00	13.00	
8	Brookwood, near Hillsboro, OR	Distrib./unattended	57.00	13.00	
9	Canby, near Barlow, OR	Distrib./unattended	57.00	13.00	
10	Cedar Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
11	Centennial, near Gresham, OR	Distrib./unattended	115.00	13.00	
12	Chemawa BPA, near Salem, OR	Distrib./unattended	115.00		
13	Chemawa BPA, near Salem, OR	Distrib./unattended	57.00		
14	Claxtar, Salem, OR	Distrib./unattended	57.00	13.00	
15	Coffee Creek, Sherwood, OR	Distrib./unattended	115.00	13.00	
16	Cornell, Portland, OR	Distrib./unattended	115.00	13.00	
17	Dilley, near Forest Grove, OR	Distrib./unattended	57.00	13.00	
18	Durham, Tigard, OR	Distrib./unattended	115.00	13.00	
19	Eagle Creek, Eagle Creek, OR	Distrib./unattended	57.00	13.00	
20	Elma, near Salem, OR	Distrib./unattended	57.00	13.00	
21	Estacada, Estacada, OR	Distrib./unattended	57.00	13.00	
22	Garden Home, near Portland, OR	Distrib./unattended	115.00	13.00	
23	Glencoe, Portland, OR	Distrib./unattended	115.00	13.00	
24	Harmony, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
25	Hayden Island, near Portland, OR	Distrib./unattended	115.00	13.00	
26	Hemlock, Portland, OR	Distrib./unattended	115.00	13.00	
27	Hillsboro, Hillsboro, OR	Distrib./unattended	57.00	13.00	
28	Hogan North, Gresham, OR	Distrib./unattended	115.00	13.00	
29	Holgate, Portland, OR	Distrib./unattended	57.00	13.00	
30	Huber, near Beaverton, OR	Distrib./unattended	115.00	13.00	
31	Jennings Lodge, Jennings Lodge, OR	Distrib./unattended	115.00	13.00	
32	Kelley Point, Portland, OR	Distrib./unattended	115.00	13.00	
33	Leland, Oregon City, OR	Distrib./unattended	57.00	13.00	
34	Lents, near Portland, OR	Distrib./unattended	115.00	13.00	
35	Lents, near Portland, OR	Distrib./unattended	57.00	11.00	
36	Main, Hillsboro, OR	Distrib./unattended	57.00	13.00	
37	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
38	Middle Grove, near Middle Grove, OR	Distrib./unattended	115.00	13.00	
39	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
40	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Mobile sub No. 2, OR	Distrib./unattended	115.00	57.00	13.00
2	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	13.00
3	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
4	Mobile Sub No. 5, OR	Distrib./unattended	115.00	57.00	13.00
5	Mobile Sub No. 6, OR	Distrib./unattended	115.00	57.00	13.00
6	Mobile Sub No. 7, OR	Distrib./unattended	115.00	57.00	13.00
7	Mobile Sub No. 8, OR	Distrib./unattended	115.00	57.00	13.00
8	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
9	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
10	Mt. Pleasant, Oregon City, OR	Distrib./unattended	115.00	13.00	
11	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
12	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
13	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
14	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
15	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
16	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
17	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
18	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
19	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
20	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
21	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
22	Rhododendron Switching, OR	Distrib./unattended	57.00		
23	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
24	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
25	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
26	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
27	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
28	Scoggins, near Gaston, OR	Distrib./unattended	57.00	13.00	
29	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
30	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
31	Springdale, near Springdale, OR	Distrib./unattended		12.50	
32	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
33	St. Louis, Gevais, OR	Distrib./unattended	57.00	13.00	
34	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
35	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
36	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
37	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
38	Tigard, Tigard, OR	Distrib./unattended	115.00	13.00	
39	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
40	Waconda, near Hopmere, OR	Distrib./unattended	57.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Wallace, Salem, OR	Distrib./unattended	57.00	13.00	
2	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	
3	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
4	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
5	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
6	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
7	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
8					
9					
10	Alder, Portland, OR	T&D/unattended	115.00	13.00	
11	Beaverton, Beaverton, OR	T&D/unattended	115.00	13.00	
12	Bell, near Portland, OR	T&D/unattended	115.00	13.00	
13	Bethany, Portland, OR	T&D/unattended	115.00	13.00	
14	Bethel, Salem, OR	T&D/unattended	230.00	115.00	13.00
15	Bethel, Salem, OR	T&D/unattended	115.00	57.00	13.00
16	Bethel, Salem, OR	T&D/unattended	115.00	13.00	
17	Blue Lake, Troutdale, OR	T&D/unattended	230.00	115.00	13.00
18	Blue Lake, Troutdale, OR	T&D/unattended	115.00	13.00	
19	Boones Ferry, Lake Oswego, OR	T&D/unattended	115.00	13.00	
20	Butler, Hillsboro, OR	T&D/unattended	115.00	13.00	
21	Canemah, Oregon City, OR	T&D/unattended	115.00	57.00	13.00
22	Canyon, Portland, OR	T&D/unattended	115.00	13.00	
23	Carver, Carver, OR	T&D/unattended	230.00	115.00	13.00
24	Carver, Carver, OR	T&D/unattended	115.00	13.00	
25	Clackamas, Clackamas, OR	T&D/unattended	115.00	13.00	
26	Cornelius, Cornelius, OR	T&D/unattended	115.00	57.00	13.00
27	Cornelius, Cornelius, OR	T&D/unattended	57.00	13.00	
28	Culver, Salem, OR	T&D/unattended	115.00	13.00	
29	Curtis, Portland, OR	T&D/unattended	115.00	13.00	
30	Dayton, near Dayton, OR	T&D/unattended	115.00	57.00	13.00
31	Dayton, near Dayton, OR	T&D/unattended	57.00	13.00	
32	Delaware, Portland, OR	T&D/unattended	115.00	13.00	
33	Denny, Beaverton, OR	T&D/unattended	115.00	13.00	
34	Dunn's Corner, near Sandy, OR	T&D/unattended	57.00	13.00	
35	E., Portland, OR	T&D/unattended	115.00	13.00	
36	E., Portland, OR	T&D/unattended	115.00	11.00	
37	Eastport, Portland, OR	T&D/unattended	115.00	13.00	
38	Fairmount, Salem, OR	T&D/unattended	115.00	13.00	
39	Fairview, Fairview OR	T&D/unattended	115.00	13.00	
40	Faraday Plant, near Estacada, OR	T&D/unattended	115.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Faraday, Switchyard, OR	T&D/unattended	115.00	57.00	13.00
2	Faraday, Switchyard, OR	T&D/unattended	57.00	11.00	
3	Glencullen, Portland, OR	T&D/unattended	115.00	13.00	
4	Glendoveer, near Portland, OR	T&D/unattended	115.00	13.00	
5	Glisan, Gresham, OR	T&D/unattended	115.00	13.00	
6	Grand Ronde, Grand Ronde, OR	T&D/unattended	115.00	57.00	13.00
7	Grand Ronde, Grand Ronde, OR	T&D/unattended	115.00	13.00	
8	Harborton, near Portland, OR	T&D/unattended	230.00	115.00	13.00
9	Harborton, near Portland, OR	T&D/unattended	115.00	13.00	
10	Harrison Sub, Portland, OR	T&D/unattended	115.00	13.00	
11	Hillcrest, Salem, OR	T&D/unattended	115.00	13.00	
12	Hogan South, Gresham, OR	T&D/unattended	115.00	57.00	13.00
13	Hogan South, Gresham, OR	T&D/unattended	115.00	13.00	
14	Indian, near Salem, OR	T&D/unattended	115.00	13.00	
15	Island, near Milwaukie, OR	T&D/unattended	115.00	13.00	
16	Kelly Butte, Portland, OR	T&D/unattended	115.00	13.00	
17	King City, King City, OR	T&D/unattended	115.00	13.00	
18	Liberty, Salem, OR	T&D/unattended	115.00	13.00	
19	Market, Salem, OR	T&D/unattended	115.00	13.00	
20	Marquam, Portland, OR	T&D/unattended	115.00	13.00	
21	McGill, Gresham, OR	T&D/unattended	115.00	13.00	
22	McLoughlin, near Oregon City, OR	T&D/unattended	230.00	115.00	13.00
23	Meridian, near Tualatin, OR	T&D/unattended	115.00	13.00	
24	Mill Creek, near Salem, OR	T&D/unattended	115.00	13.00	
25	Monitor, near Monitor, OR	T&D/unattended	230.00	57.00	13.00
26	Murrayhill, Beaverton, OR	T&D/unattended	115.00	13.00	
27	Murrayhill, Beaverton, OR	T&D/unattended	230.00	115.00	13.00
28	Newberg, Newberg, OR	T&D/unattended	115.00	13.00	
29	Oak Grove, Three Lynx, OR	T&D/unattended	115.00	13.00	
30	Oak Grove, Three Lynx, OR	T&D/unattended	115.00	11.00	
31	Oak Grove, Three Lynx, OR	T&D/unattended	13.00	11.00	
32	Oak Grove, Three Lynx, OR	T&D/unattended	13.00	0.48	
33	Orenco, near Hillsboro, OR	T&D/unattended	115.00	57.00	13.00
34	Orenco, near Hillsboro, OR	T&D/unattended	115.00	13.00	
35	Oswego, Lake Oswego, OR	T&D/unattended	115.00	13.00	
36	Oxford, Salem, OR	T&D/unattended	115.00	13.00	
37	Pleasant Valley, near Portland, OR	T&D/unattended	115.00	13.00	
38	Portsmouth, Portland, OR	T&D/unattended	115.00	13.00	
39	Progress, near Tigard, OR	T&D/unattended	115.00	13.00	
40	Reedville, near Beaverton, OR	T&D/unattended	115.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	River Mill, near Beaverton, OR	T&D/unattended	57.00	11.00	
2	Rivergate North Yard, Portland, OR	T&D/unattended	230.00	115.00	13.00
3	Rivergate South Yard, Portland, OR	T&D/unattended	115.00	13.00	
4	Rivergate South Yard, Portland, OR	T&D/unattended	115.00	11.00	
5	Rock Creek, near Portland, OR	T&D/unattended	115.00	13.00	
6	Rosemont, near Lake Oswego, OR	T&D/unattended	115.00	13.00	
7	Round Butte, near Madras, OR	T&D/unattended	500.00	230.00	12.00
8	Round Butte, near Madras, OR	T&D/unattended	230.00	13.00	
9	Ruby, Gresham, OR	T&D/unattended	115.00	13.00	
10	Scappose, Scappose, OR	T&D/unattended	115.00		
11	Scholls Ferry, Beaverton, OR	T&D/unattended	115.00	13.00	
12	Sellwood, Portland, OR	T&D/unattended	115.00	57.00	13.00
13	Sellwood, Portland, OR	T&D/unattended	115.00	13.00	
14	Shute, Hillsboro, OR	T&D/unattended	115.00	34.50	
15	Six Corners, Six Corners, OR	T&D/unattended	115.00	13.00	
16	Springbrook, Newberg, OR	T&D/unattended	115.00	13.00	
17	St. Helens, near St. Helens, OR	T&D/unattended	115.00		
18	St. Marys, West Yard, Beaverton, OR	T&D/unattended	230.00	115.00	13.00
19	St. Marys, East Yard, Beaverton, OR	T&D/unattended	115.00	13.00	
20	Sullivan, West Linn, OR	T&D/unattended	115.00	13.00	
21	Sullivan, West Linn, OR	T&D/unattended	57.00	4.15	
22	Sunset, near Hillsboro, OR	T&D/unattended	115.00	13.00	
23	Sunset, near Hillsboro, OR	T&D/unattended	115.00	34.50	
24	Tabor, Portland, OR	T&D/unattended	115.00	13.00	
25	Tabor, Portland, OR	T&D/unattended	57.00		
26	Tektronix, Beaverton, OR	T&D/unattended	115.00	13.00	
27	Town Center, Portland, OR	T&D/unattended	115.00	13.00	
28	Trojan, near Rainier, OR	T&D/unattended	230.00	13.00	
29	Tualatin, Tualatin, OR	T&D/unattended	115.00	13.00	
30	University, Salem, OR	T&D/unattended	115.00	13.00	
31	Urban, Portland, OR	T&D/unattended	115.00	13.00	
32	West Portland, Lower Yard, Tigard, OR	T&D/unattended	115.00		
33	West Portland, Upper Yard, Tigard, OR	T&D/unattended	115.00	13.00	
34	West Union, near Hillsboro, OR	T&D/unattended	115.00	13.00	
35	Willsonville, near Willsonville, OR	T&D/unattended	115.00	13.00	
36					
37					
38	Bakeoven, BPA, near Bakeoven, OR	Transm./unattended	500.00		
39	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
40	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Biglow Canyon Wind Farm, Wasco, OR	Transm./unattended	230.00	34.50	13.00
2	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
3	Boardman, OR	Transm./unattended	230.00	7.20	
4	Boardman, OR	Transm./unattended	24.00	7.20	
5	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
6	Buckley, BPA near Buckley, WA	Transm./unattended	500.00		
7	Captain Jack, BPA, near Malin, OR	Transm./unattended	500.00		
8	Carty, near Boardman, OR	Transm./unattended	500.00	21.00	
9	Carty, near Boardman, OR	Transm./unattended	16.00	7.20	4.20
10	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
11	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
12	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
13	Forest Grove, Forest Grove, OR	Transm./unattended	115.00		
14	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
15	Grassland, near Boardman, OR	Transm./unattended	500.00		
16	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
17	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
18	Horizon, Hillsboro, OR	Transm./unattended	230.00	115.00	13.00
19	Keeler, BPA, Hillsboro, OR				
20	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
21	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
22	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	0.48
23	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
24	Pelton, near Madras, OR	Transm./unattended	230.00	13.00	
25	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
26	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	
27	Port Westward, near Clatskanie, OR	Transm./unattended	13.00	4.20	
28	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
29	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
30	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
31	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
32	Troutdale, BPA near Troutdale OR	Transm./unattended	230.00		
33	Tucannon Mullan Switchyard, Dayton, WA	Transm./unattended	230.00	34.50	13.00
34	TOTAL MVa		31707.00	5408.93	432.68
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
69	9		Capacitor Banks	3	16	1
45	2		Capacitor Banks	4	12	2
15	2					3
42	2		Capacitor Banks	2	7	4
20	1		Capacitor Banks	2	3	5
42	2		Capacitor Banks	2	6	6
24	2		Capacitor Banks	1	12	7
28	1		Capacitor Banks	2	6	8
39	4					9
56	2		Capacitor Banks	4	13	10
56	2		Capacitor Banks	4	12	11
						12
						13
28	1		Capacitor Banks	2	6	14
28	1		Capacitor Banks	2	6	15
28	1		Capacitor Banks	2	6	16
13	1		Capacitor Banks	3	9	17
56	2		Capacitor Banks	4	13	18
14	1					19
56	2		Capacitor Banks	4	12	20
30	2		Capacitor Banks	2	4	21
28	1					22
25	1		Capacitor Banks	2	6	23
50	2		Capacitor Banks	4	12	24
34	2		Capacitor Banks	4	12	25
28	1		Capacitor Banks	2	6	26
43	2		Capacitor Banks	4	14	27
56	2		Capacitor Banks	4	12	28
39	2		Capacitor Banks	2	7	29
56	2		Capacitor Banks	2	6	30
53	2					31
56	2		Capacitor Banks	4	12	32
28	1		Capacitor Banks	2	6	33
22	1					34
20	2					35
84	3		Capacitor Banks	6	20	36
23	3					37
53	2		Capacitor Banks	4	12	38
34	2		Capacitor Banks	1	4	39
15	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
34	1					1
29	1					2
34	1					3
34	1					4
34	1					5
25	1					6
25	1					7
42	2		Capacitor Banks	4	9	8
20	1		Capacitor Banks	3	15	9
45	2		Capacitor Banks			10
39	2		Capacitor Banks	3	10	11
31	3		Capacitor Banks	3	15	12
20	1		Capacitor Banks	4	18	13
28	2					14
56	2		Capacitor Banks	4	14	15
						16
28	1		Capacitor Banks	2	6	17
28	1		Capacitor Banks	2	6	18
28	1		Capacitor Banks	2	7	19
28	1		Capacitor Banks	2	6	20
22	1					21
						22
28	1		Capacitor Banks	2	6	23
78	3		Capacitor Banks	5	15	24
28	1	1	Capacitor Banks	2	6	25
45	2		Capacitor Banks	4	12	26
28	1		Capacitor Banks	2	6	27
13	2		Capacitor Banks	1	11	28
17	1		Capacitor Banks	3	16	29
42	2					30
						31
						32
24	2		Capacitor Banks	2	7	33
8	1					34
14	1					35
53	2		Capacitor Banks	4	12	36
22	1		Capacitor Banks	2	6	37
45	2		Capacitor Banks	4	12	38
28	1	1	Capacitor Banks	3	19	39
41	2		Capacitor Banks	2	6	40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
28	1	1	Capacitor Banks	2	6	1
10	1		Capacitor Banks	1	12	2
18	2		Capacitor Banks	2	6	3
31	2		Capacitor Banks	2	8	4
20	1					5
42	2		Capacitor Banks	4	13	6
15	2		Capacitor Banks	1	2	7
						8
						9
56	2		Capacitor Banks	2	6	10
34	2		Capacitor Banks	4	12	11
66	3		Capacitor Banks	4	12	12
56	2		Capacitor Banks	5	15	13
564	2					14
140	1					15
28	1		Capacitor Banks	2	6	16
640	2					17
56	2		Capacitor Banks	2	6	18
50	2		Capacitor Banks	2	7	19
300	2		Capacitor Banks	8	75	20
250	6					21
200	4		Capacitor Banks	8	29	22
640	2					23
56	2		Capacitor Banks	4	12	24
41	2		Capacitor Banks	4	13	25
140	1					26
28	1		Capacitor Banks	2	6	27
28	1					28
17	1		Capacitor Banks	2	6	29
125	1					30
20	2		Capacitor Banks	4	6	31
28	1					32
56	2		Capacitor Banks	2	6	33
14	1		Capacitor Banks	2	3	34
208	5		Capacitor Banks	4	29	35
132	4		Capacitor Banks	2	32	36
17	1					37
25	1		Capacitor Banks	1	4	38
50	2		Capacitor Banks	1	3	39
27	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
140	1					1
32	2					2
24	1		Capacitor Banks	2	6	3
50	2		Capacitor Banks	4	12	4
45	2		Capacitor Banks	4	12	5
33	1	1				6
13	1		Capacitor Banks	2	3	7
320	1					8
50	2		Capacitor Banks	6	19	9
28	1		Capacitor Banks	2	6	10
28	1		Capacitor Banks	2	6	11
125	3					12
56	2		Capacitor Banks	4	12	13
56	2		Capacitor Banks	3	11	14
45	2		Capacitor Banks	4	12	15
45	2		Capacitor Banks	2	6	16
56	2		Capacitor Banks	4	12	17
50	2		Capacitor Banks	3	10	18
28	1		Capacitor Banks	2	6	19
250	5		Capacitor Banks	10	54	20
75	3		Capacitor Banks	6	18	21
640	2					22
84	3		Capacitor Banks	6	19	23
17	1		Capacitor Banks	2	6	24
125	1					25
56	2		Capacitor Banks	3	11	26
320	1					27
45	2		Capacitor Banks	4	12	28
8	1					29
64	2					30
						31
						32
280	2	1	Capacitor Banks	6	18	33
81	3					34
34	2		Capacitor Banks	2	7	35
50	2		Capacitor Banks	4	12	36
56	2		Capacitor Banks	4	12	37
28	1					38
50	2		Capacitor Banks	4	14	39
84	3		Capacitor Banks	6	18	40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
32	2					1
520	4	1	Capacitor Banks	1	24	2
22	1		Capacitor Banks	2	7	3
22	1		Capacitor Banks	2	7	4
28	1		Capacitor Banks	2	6	5
28	1		Capacitor Banks	2	6	6
561	3		Reactors	12	180	7
394	4	2				8
28	1		Capacitor Banks	2	6	9
						10
28	1		Capacitor Banks	2	6	11
140	1		Capacitor Banks	1	24	12
28	1		Capacitor Banks	2	6	13
100	2	1	Capacitor Banks	4	18	14
49	2		Capacitor Banks	2	6	15
56	2		Capacitor Banks	5	36	16
			Capacitor Banks	1	24	17
960	3		Capacitor Banks	3	108	18
56	2		Capacitor Banks	4	12	19
45	2		Capacitor Banks	4	12	20
33	1					21
400	8		Capacitor Banks	25	150	22
375	3					23
22	1		Capacitor Banks	2	6	24
						25
84	3		Capacitor Banks	6	18	26
56	2		Capacitor Banks	2	6	27
56	2					28
56	2		Capacitor Banks	4	13	29
22	1		Capacitor Banks	2	7	30
112	4		Capacitor Banks	5	16	31
			Capacitor Banks	1	24	32
56	2		Capacitor Banks	4	13	33
56	2		Capacitor Banks	4	12	34
84	3		Capacitor Banks	6	18	35
						36
						37
						38
464	4	1				39
170	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
480	3					1
685	3	1				2
55	1					3
55	1					4
80	3					5
						6
						7
596	2	1				8
22	1					9
164	3					10
100	2					11
300	3	1				12
						13
			Series Capacitor	1	363	14
						15
572	2					16
						17
640	2					18
						19
168	1					20
			Reactors	3	180	21
53	3	1				22
						23
120	3	1				24
3	1					25
900	3	1				26
40	2					27
			Series Capacitor	1	546	28
640	2					29
						30
			Series Capacitor	1	546	31
						32
320	2		Capacitors/Reactors	6	90	33
21543	386	16		451	3,677	34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 12 Column: a

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

Schedule Page: 426 Line No.: 13 Column: a

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

Schedule Page: 426.1 Line No.: 16 Column: a

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

Schedule Page: 426.1 Line No.: 22 Column: a

Switching only.

Schedule Page: 426.1 Line No.: 31 Column: a

Regulating only.

Schedule Page: 426.1 Line No.: 32 Column: a

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

Schedule Page: 426.4 Line No.: 7 Column: a

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.

Schedule Page: 426.4 Line No.: 8 Column: a

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.

Schedule Page: 426.4 Line No.: 10 Column: a

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.4 Line No.: 17 Column: a

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.4 Line No.: 25 Column: a

Switching only

Schedule Page: 426.4 Line No.: 32 Column: a

Switching only

Schedule Page: 426.4 Line No.: 38 Column: a

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

Schedule Page: 426.5 Line No.: 2 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 3 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 4 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 5 Column: a

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

Schedule Page: 426.5 Line No.: 6 Column: a

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

Schedule Page: 426.5 Line No.: 7 Column: a

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

Schedule Page: 426.5 Line No.: 10 Column: a

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Portland General Electric Company		/ /	2020/Q4
FOOTNOTE DATA			

is reported.

Schedule Page: 426.5 Line No.: 11 Column: a

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

Schedule Page: 426.5 Line No.: 12 Column: a

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

Schedule Page: 426.5 Line No.: 13 Column: a

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

Schedule Page: 426.5 Line No.: 14 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 17 Column: a

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

Schedule Page: 426.5 Line No.: 19 Column: a

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

Schedule Page: 426.5 Line No.: 21 Column: a

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

Schedule Page: 426.5 Line No.: 23 Column: a

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

Schedule Page: 426.5 Line No.: 24 Column: a

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.

Schedule Page: 426.5 Line No.: 25 Column: a

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.

Schedule Page: 426.5 Line No.: 28 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 30 Column: a

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

Schedule Page: 426.5 Line No.: 31 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 32 Column: a

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

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2				
3	Lease Payments for Corporate Headquarters	121 SW Salmon Street Corp	418	8,521,304
4	OPUC Order No. 18-823			
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22	Administrative Services	Salmon Springs Hospitality Group	186	934,198
23	Administrative Services	121 SW Salmon Street Corp	146	1,622,181
24				
25				
26				
27				
28				
29				
30				
31				
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42				

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